Draft Workshop Report:
Interim Emissions Performance Standard Program Framework, R.06-04-009
June 21-23, 2006

Prepared by Commission Staff, August 21, 2006

The California Public Utilities Commission ("CPUC" or "Commission") convened a three-day workshop in its climate change policy proceeding, R.06-04-009, on June 21-23, 2006 in San Francisco. This workshop considered the design and implementation structure of an interim emissions performance standard ("EPS") program prior to implementation of a greenhouse gas (GHG) cap that would apply to the three major investor-owned electric utilities ("IOUs")[1], its jurisdictional energy service providers ("ESPs"), and community choice aggregators ("CCAs") that operate within an IOU's territory. This Report outlines the background and purpose of the workshops, reviews participants' comments on key points, summarizes the advantages and disadvantages that participants attributed to key issues associated with an interim EPS program, and includes a revised version of the staff proposal for an EPS program. Appendices include a list of the workshop participants, a summary of the pre-workshop written comments, the data requested at the workshop and subsequent responses, the staff proposal, and questions posed to parties for post-WS comment.

Throughout this report, we use the term "greenhouse gas"[2] or "GHG" (rather than "carbon" or "CO2") to refer to the types of emissions that would be addressed in an EPS, even though CO2 reductions may be the primary focus in the near term. This recognizes that the full scope of GHG emissions will ultimately need to be included in the strategies to mitigate climate change.

## I. Background and Purpose of the Workshop

In the October 6, 2005 GHG Policy Statement, the Commission describes a GHG emissions performance standard that would limit the GHG emissions levels for all new utility-owned generation and all long-term procurement contracts to "no higher than the GHG emissions levels of a combined-cycle natural gas turbine."

The Commission's objective in scheduling this workshop was to identify key issues to consider when contemplating an EPS, and to develop an EPS program proposal that would incorporate policy, design and implementation issues identified by parties and staff. The EPS discussion and proposal was limited to an interim GHG EPS program intended to serve as a near-term bridge to the load-based GHG cap adopted by the Commission in D.06-02-032, and to the extent possible, form consensus among parties.

[1] We use the term "IOUs" to refer collectively to Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), and Southern California Edison Company (SCE), the utility respondents to the this proceeding.

[2] Primary greenhouse gases influenced by humans are carbon dioxide (CO2), methane (CH4), nitrous oxide (N2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF6). Visit the EPA's website at http://yosemite.epa.gov/oar/globalwarming.nsf/content/emissions.html for a more thorough overview of GHGs.

The development of an interim GHG EPS is identified as "Phase 1" of R.06-04-009, with "Phase 2" focusing on design and implementation of a load-based cap.

As discussed at the May 10, 2006 Pre-Hearing Conference on the matter, and subsequently described in the June 1 Ruling, Phase 1 will address the following key questions:

(a) Should the Commission adopt an interim GHG EPS to guide ongoing electric procurement decisions while it takes the necessary steps to fully implement D.06-02-032?
(b) If the Commission elects to adopt such a standard, how should it be designed and implemented so that it can be put in place quickly to serve this purpose?

The language of the OIR indicates that the Commission did not intend to restrict the design of the performance standard to the one specifically set forth in the 2005 GHG Policy Statement. In the context of Phase 1, however, the specific purpose of an interim performance standard may dictate many of the relevant design and implementation parameters. As discussed at the PHC, certain "bells and whistles" (e.g., offsets) to a performance standard that the Commission may wish to consider in the context of a load-based cap do not appear to be feasible in the context of an interim standard that needs to be put in place quickly.

Accordingly, deviations from the performance standard design set forth in the 2005 GHG EPS Policy Statement may be considered in Phase 1, but only to the extent that such deviations would not significantly delay the implementation of an interim EPS.

To help focus party preparation for this workshop, the assigned Administrative Law Judge (Judge Gottstein) circulated a proposed agenda and pre-workshop questions prepared by CPUC staff on May 31, 2006. Judge Gottstein directed interested parties to file pre-workshop comments in response to the questions posed and to identify other issues, if any, that the CPUC should take into consideration at the workshops. A list of those parties filing pre-workshop opening and reply comments is included in the summary of those comments presented in Appendix A of this report. This summary was also provided to all attendees at the workshops.

Approximately 90 individuals, representing about 50 different stakeholders, attended one or more days of the workshop. Appendix B presents a list of these workshop participants. This workshop report cannot fully reflect all of the discussion throughout the three-day workshop. Instead, the sections entitled "Workshop Participant Comments" in the body of this report are intended to highlight the major issues raised during the discussion, rather than to present a detailed summary of each participant's position.

## II. Workshop Structure and Scope

Based upon the proposed agenda included in the June 1 Ruling and pre-workshop comments, staff structured the workshop to address three overlapping categories relevant to the design and implementation of an EPS: 1) Policy Overview and Basic EPS Structure, 2) Standard-setting and Implementation Details, and 3) Design Summary, Implementation Issues, and Next Steps. In addition, a staff straw proposal was presented for discussion on Days 2 and 3. Workshop discussion was structured to identify policy issues of primary concern when considering whether to pursue an EPS program, followed by discussion of key design and implementation issues associated with an EPS program.

On May 31, 2006 CPUC staff further clarified the scope of the workshop by including pre-workshop questions (see Appendix C). On June 1, 2006 Judge Gottstein's Ruling[3] provided additional direction on the scope of phase 1 and indicated the two primary umbrella issues to be addressed: (a) Should the Commission adopt an interim GHG emissions performance standard to guide ongoing electric procurement decisions while it takes the necessary steps to fully implement D.06-02-032; and (b) If the Commission elects to adopt such a standard, how should it be designed and implemented so that it can be put in place quickly to serve this purpose? Judge Gottstein also asked parties to present their best available assessment costs, benefits, and co-benefits.

CPUC staff and consultant[4] began the workshop with an overview of the major areas to be considered in each of the three days: policy overview and basic EPS structure (Day 1); standard-setting and implementation details, including discussion of a staff straw proposal (Day 2); EPS design summary and implementation details, including continued discussion of the staff straw proposal (Day 3)[5]. The data requested at the workshop are attached as Appendix D, and the staff straw proposal resulting from this discussion is included as an attachment to Appendix E. In the sections below, we summarize the workshop discussion on a day-by-day basis. Readers are encouraged to refer to the materials in the appendices as they review this summary.

## III. Policy Overview and Basic EPS Structure Discussion (Day 1)

CPUC staff provided an overview of the context for consideration of an interim EPS, and a brief overview of the existing EPS Policy Statement. In addition, staff provided copies of parties' pre-workshop comments to all participants at the workshop (see Appendix A). Emphasis was placed on pursuing focused discussion to identify areas of agreement, where possible, and to identify key issues associated with consideration and/or design of an interim EPS.

The structure of discussion followed the order of questions posed for pre-workshop comment. The responses have been categorized and summarized based upon the flow of discussion during the workshop days.

### A. Workshop Participant Comments on Policy Overview Questions: General Considerations

[3] http://www.cpuc.ca.gov/EFILE/RULC/56888.pdf
[4] Richard Cowart of the Regulatory Assistance Project assisted CPUC staff in framing the workshop and developing the straw proposal, and led the workshop discussions.
[5] The agenda for the workshop is posted at www.cpuc.ca.gov/static/hottopics/1energy/ghgperformancestandardworkshopagenda+_june+21_23.pdf

Staff then posed the following "Policy Overview" questions for discussion to identify the key areas of agreement and of concern.

**1a. Should the Commission adopt an interim EPS to guide ongoing electric procurement decisions pending adoption of a long-term cap and trade program? Identify principal policy arguments, pro and con; and**

Responses to Q1a

- The existing carbon adder policy adopted and implemented by the CPUC makes an EPS unnecessary as it achieves the same goal of preventing backsliding to higher emitting resources than those currently included in the IOU and ESPs portfolio mix. (IEP)

- An EPS supports the Governor's Executive Order setting GHG emission reduction goals. An EPS should stay in effect even after a cap and trade program is implemented. (NRDC)

- The adder is complimentary to EPS but does not replace. Open question as to how an EPS might interact with reliability risks. IOUs should include an EPS scenario with existing procurement plans. (TURN)

- The CPUC could increase the adder amount to meet some of the same near-term goals as an EPS. However, an EPS essentially requires existing ratepayers to pay for externalities associated with GHGs while the existing adder places the bulk of the burden on future generations as it does not take into account costs beyond a certain price point and is advisory only. The adder still allows high emitting plants into the procurement mix whereas an EPS sets a minimum standard. (CEC)

- The CPUC already has oversight over new LT contracts anyway so EPS is unnecessary. (SCE)

- The CPUC should set clear requirements for procurement up front. Before going through an involved RFP process requiring time and money, LSEs should know with certainty the CPUC's contract and generation requirements. Waiting for the CPUC to weigh in at the end of the process is counter-productive. Issues: costs, reliability, support adder. Concerned about excluding too many resources. (PG&E)

- The effect of an EPS impact would be insignificant as the CPUC already has existing policies that prevent backsliding such as the RPS and EE. (EPUC)

- The CPUC has oversight of long-term procurement. LSEs need clear and unambiguous signal to prevent investment in new power plants and contracts of highest emitting variety. New coal is an issue. The EPS provides the clear signal needed to ensure clean energy investment. (GPI)

- The adder is problematic because it's difficult to determine the "right" value. Development of an interim EPS may interfere with development of a cap and trade program, and new technologies may be disincented. (SF Community Power)

- Investment decisions are happening now in the interior west including new non-advanced coal facilities and transmission to bring coal to California. A carbon adder is anticipated compliance cost, whereas an EPS looks at an actual emissions threshold. (WRA)

- The carbon adder allows for consideration of other attributes- reliability, costs, etc, that an EPS does not. EPS seems to draw a line in the sand. (SDG&E)

- Ongoing monitoring of contracts and investments would create uncertainty and significantly affect market. (IEP, PG&E)

- An EPS should include dispatch consideration and peakers. (League of Women Voters)

- An EPS is overly prescriptive regarding technology choice. (Constellation)

**1b. If the Commission decides to adopt an interim EPS, what goals are most important in guiding its design and implementation?**

Responses to Q1b

- The purpose of an EPS is to prevent investment and contracting with resources that are higher emitters than what we have in the system today and therefore prevent "backsliding." CA is the load center in WECC. Need to lead. (GPI)

- General concerns expressed regarding the possibility of developing overly prescriptive policies. (EPUC)

- EPS necessary to prevent the increasing emissions prior to implementation of a future cap. Encourages technological innovation. (NRDC)

- EPS should be comprehensive and apply to all LSEs. (PG&E)

- Don't include ESPs. Emissions are negligible from ESPs and long-term contracting is limited. (AReM)

- EPS should be designed to transition well to / integrate with a cap. (SF Community Power)

- Appropriate design depends on whether EPS would apply to existing and/or new facilities. (SCE)

- Need to know how an EPS would link to existing procurement policies. (Constellation)

### B. <u>Workshop Participant Comments on Basic EPS Structure</u>

Staff then posed the following EPS Basic Structure questions for discussion to identify the key areas of agreement and of concern.

**2. If an interim EPS is adopted, to which Load Serving Entities (LSEs) should it apply?**

Responses to Q2: To which LSEs should an interim EPS apply?

- Energy Service Providers (ESP) should not be included in an EPS program as their procurement process is not the same as IOUs and they represent a small portion of total load. Implementation delays and extra costs would be likely if ESPs were required to participate. (AReM)

- ESPs can have a significant impact on market, especially if wholesale costs drop and as DWR contracts expire, ESPs can sign up more contracts. The argument that ESPs don't enter into significant long-term contracts is not persuasive. If they don't enter into long-term contracts, then ESP compliance with the program would be negligible. If they do enter into significant long-term contracts, they should be included. Either way, it makes sense to include them as part of an EPS. Prefer comprehensive statewide policy including munis. If munis are not included, it then creates competitive problems for utilities statewide. Need to understand impacts of CA energy markets if munis are exempt from program Programs need to be at minimum statewide, and policies need to coordinate with legislation. (PG&E, SCE)

- The CPUC Long-Term Procurement Docket has teed up the issue for Phase II as to how ESPs may be required to come into procurement process. (CPUC Energy Division)

- Open issue of how to deal with system contracts and allocation for multi-state, multi-jurisdictional entity. (Mid-American/PacifiCorp)

- The program should focus on the public good and be applied to munis also. (League of Women Voters)

- Munis do not need to be included in an EPS program as they are more responsive than IOUs. (NorCal Power Agency)

- CPUC sets standard that creates pressure on other entities, e.g. munis. The program should aim to accomplish all that it can for CPUC jurisdictional LSEs. (GPI)

- An EPS program needs to be coordinated with legislation. (IEP)

**3. Over what time frame should an interim EPS be implemented?**

Responses to Q3: Over what timeframe should an interim EPS remain in place?

- Current CPUC procurement process reviews a significant number of short-term contracts. The number of contracts of 5 years and greater are much more limited. Currently reviewing one long-term contract submitted by PG&E. Anticipate SCE will soon file long-term contracts with the CPUC as well. (CPUC Energy Division).

- EPS should remain in place until a more comprehensive program is implemented. Note that the program doesn't necessarily have to be a CPUC program. (PG&E)

- The CPUC should not pursue an EPS program and should instead wait for state, regional, or federal action. (EPUC)

**4. To which power sources should an EPS apply?**

Responses to Q4: To which power sources should an interim EPS apply?

- Program should include contracts/facilities of 5 MW and greater as that is consistent with SGIP. The EPS should apply to all long-term contracts including IOU owned, repowered facilities. IGCC should be included if sequestration is part of the technology. (NRDC)

- Program should include contracts of 25MW for greater consistency with RGGI, CARB. Some exemptions should be made based upon size. (EPUC)

- Peakers should not necessarily be exempted as that may incent more peakers into the system. (DRA, League of Women Voters)

- Air Boards won't let more peakers into the system so DRA's concern in moot. Also applying standard to peakers to get additional savings not fair since goal is to prevent backsliding. (PG&E)

- Including small peakers in an EPS would be administratively challenging. (AReM)

- In-state, out-of-state, existing, new, and in state renewals of contracts should be included. (Redefining Progress)

- Repowering needs to be defined. (PG&E)
- Existing plants should not be included. Only new plants should be part of the program. (SCE)
- New long-term contracts should be included. (GPI)
- Concerns raised about additional costs to ratepayers regarding resource adequacy in meeting an interim EPS. (Constellation)
- If existing contracts covered then concern that IOUs are advantaged over IPPs because they do not enter into contracts with their own generation. (Constellation)
- If existing plants are grandfathered under the EPS, then risk losing the motivation to retire, repower, or otherwise invest in cleaner resources. (CEC)
- QFs should be exempt because IOUs are required to take those contracts. In addition, combined heat and power (CHP) should be exempt because of dual use of fuel. Some discussion of a proposal to calculate emissions from co-generation facilities. (EPUC)
- Five-year or longer term of contracts should be included as that is consistent with a carbon adder and long-term procurement policies. (PG&E).
- If standard is 5 years, there is a concern that plants will be contracted for shorter periods in order to bypass the EPS. (UCS).

## IV. Standard-setting and Implementation Details Discussion (Day 2)

CPUC staff began Day 2 by moving directly into discussion and shaping of an interim EPS program including definition of the standard, compliance and monitoring, and flexible compliance options. The agenda continued to follow the order of the pre-workshop comment questions.

In the afternoon session, a staff straw proposal was provided for discussion. The straw proposal was further discussed and finessed the following day.

### A. Workshop Participant Comments on Standard-setting and Implementation Details

**Question 5: What is the standard, and the technical basis for setting it?**

Responses to Q5:

- The standard should be based upon emissions per MW equal to a "well functioning" CCGT. CPUC should coordinate with CEC to determine an appropriate CCGT emissions factor. IGCC plus sequestration should be considered in meeting the standard. (NRDC)

- Baseload definition could use 60% as cutoff capacity factor, but provisions for reliability issues should be included. (PG&E)
- Average of CEMS/eGRID data (excluding outliers) could be used as an emissions factor proxy. Alternatively, net system average could also be a solution. (CEC)
- CEC and NRDC proposals do not address actual emissions due to efficiencies, or lack of, associated with transmission/distribution/locational issues. (IEP)
- Need to have a shared definition of CCGT. (Sempra)
- Objects to "well functioning" as part of the metric proposed by NRDC. SDG&E wants technology to be the standard with multi-attributes for varying technologies. (SDG&E)
- Baseload renewables should be included. Renewable Energy Credits need to come with purchase, or have emissions factor assigned. Standard should be more aggressive than a CCGT emissions average to meet the Governor's targets. (CRS)
- More important to determine the goal of the program but don't name specific technology. (EPUC)
- CCGT should be the standard. (GPI)
- If a technology based gateway screen is used, then the operational aspects of a plant may be unimportant. Intensity per MWh should be the metric. (CCAR)
- How to handle repowering of existing plants? (Redefining Progress)
- One single standard should be used for new and repowered plants. (IEP)
- Single standard should be applied to all resources. (GPI, SDG&E)
- Qualifying facilities should not be included since IOUs are required to take their power. (PG&E)
- Should use the 95$^{th}$ percentile standard- best available not just an average standard of existing plants. (Redefining Progress)
- Standard should be set in a way that avoids gaming and makes sure that unspecified contracts are accurately accounted. (CRS)
- Should have an R&D exemption to encourage other technologies. (EPUC)

**Question 6: How can compliance with the standard be determined?**

Participants generally agreed that the CPUC should provide an initial review of baseload contracts eligible for the EPS. Once those contracts are approved, no further review would be necessary. Parties understood that underlying resources might have varying heat rates, that dispatch is beyond an LSE's control, and the interim EPS would be a rough screen. The concept was to implement something in the near-term that would address the primary goals of an EPS.

Key issues to address focused on unspecified resources and repowering of units. The majority of participants agreed that one standard should apply to all resources- as opposed to one standard for new resources, and another for existing and repowered resources. Various proxy options for unspecified resource emission factors were discussed; 1) average emissions from coal generation, 2) WECC average, 3) geographical averages, and 4) CEC's CA net system power average which is the average of the leftover energy in the system that is not claimed- includes in and out of state power, and anything that is not claimed by a CA utility.

Responses to Q6:

- Operational and dispatch impacts should also be included in the program. (League of Women Voters)
- System sales should be limited to less than 5 years and therefore would not hit the gateway. (EPUC)
- No time/duration limit should be imposed upon unspecified resources. (AReM)
- Unspecified resources are an issue with an EPS and also with a cap. Eventually, we need to deal with it, so we should deal with it now. (GPI)
- Is there a potential role in assigning a value to unspecified resources using CCAR or some other methodology? (AReM)
- In a case of "blended" baseload contracts, if one resource does not make it, then the blend should not qualify. (NRDC, Redefining Progress)
- NRDC's proposal could penalize wind and other renewables. (AReM)
- If the proposed contract as a whole passes the test, then it should qualify. (Sempra)
- For unspecified resources, apply emissions factor from the region from which the energy is produced since in most situations it is known where the power is coming from. If average emissions from coal is used as a proxy, it creates a perverse incentive to actually purchase coal. (PG&E )

- For unspecified resources, average emissions from coal should be the default. (NRDC)

- SCE is not currently doing any long-term deals for unspecified resources. Not sure that geographical average is the right approach as an LSE might know the delivery point for energy, but doesn't necessarily know what is behind it. (SCE)

- Renewable power that enters into the system with its Renewable Energy Credits (RECs) assigned to another entity, should not be treated as renewable. Instead, it should be treated as "null" power and assigned a system average of some sort to avoid double counting of renewable attributes. (CRS)

Questions posed by CPUC to parties at this point:

1. Can you "green up" power that would not otherwise qualify?
2. Can you use "null" renewables (renewables that have been stripped of RECs)

- Don't penalize renewables at this point. We want to encourage as many renewables into the system as we can. We should bring them in as clean, especially since CPUC jurisdictional LSEs cannot currently trade RECs so the double counting issue for them is not significant. (GPI)

- Null renewable power should not be considered a renewable resource as the renewable attributes have been sold to another entity. (CRS)

**Question 7: What compliance and monitoring procedures and monitoring are needed?**

Responses to Q7:

- IOUs are required already to demonstrate compliance to the CPUC. This would be an additional component of the approval process. Once approved, the IOUs' contracts would be considered compliant, and subject to audits and spot checks. (PG&E, Constellation)

- LSEs could do a simple resource adequacy filing after the fact. Alternatively, they could provide an advance filing to the CPUC signaling their activity. (AReM)

- As long as the screen is in effect and if all contracts qualify, then no need to do work after the fact. (GPI)

- Require supply contracts to commit to delivery terms. If it does not happen, then the suppliers are in breach. (IEP)

- Might need to check that the plants are running in the way they were supposed to. (Redefining Progress, CCAR)

- Cogen plants have to show efficiency demonstration to FERC in order to be approved. If things change, they have to be recertified by FERC. Regarding ongoing compliance, if marketer changes mix, they are on the hook financially. (EPUC)

- Emissions ought to be specified as condition of contract. (NRDC)

**Question 8: Flexible compliance options**

Responses to Q8:

- No safety valve needed as long as the screen allows for case by case review. (PG&E)

- Safety valve may make sense. Want to see offsets as part of a longer term emissions policy, but not sure if needed with interim EPS. (SCE)

- No offsets should be included in the EPS. (NRDC)

- Any early action credits should be addressed in Phase II implementation of a load-based cap. (IEP, NRDC)

- Sempra's recent experience demonstrates difficulty of using offsets to "clean" energy resources that are large emitters. Their recent attempt to do so was unsuccessful due to concerns about 3rd party vendors. (Sempra)

- This program should be coordinated with current bills pending before the CA legislature. (PG&E)

## B. Staff Straw Proposal

On the afternoon of Day 2, staff introduced a straw proposal based upon the workshop discussion thus far. That straw proposal, including the modifications made based upon discussion at the workshop, is described below and is illustrated in Appendix E as part of the directions for post-workshop comments. Discussion of post-workshop comments and an updated staff proposal reflecting comments is addressed in a subsequent section.

### 1. Design Goals for the EPS

a. Prevent backsliding and commitments that will make future GHG reductions more difficult
b. Minimize costs to ratepayers and minimize the risk of long-term commitments that will raise the cost of future compliance costs
c. Reliability:

i. short-term: do not force shutdown of essential facilities
ii. long-term: consider risks of relying on high emitting resources

d. Administrative simplicity

**2. Timeframe**

a. Coordinate with procurement proceeding, but adopt now
b. Implement performance standard as interim measure for an unspecified period of time. CPUC will re-evaluate the program when a GHG cap and trade system or other relevant policy (CPUC, state, regional, or other) is functioning.

**3. To Which LSEs does the EPS apply?**

a. Apply to all jurisdictional LSEs (including ESPs and CCAs)
b. Create ESP process to address ESP procurement related to this program
c. Do not delay pending legislation regarding publicly-owned utilities
d. Develop a filing/approval process for multi-jurisdictional utilities, including a protocol for allocating emissions among resources serving multiple states

4. **Program Screens**

a. The EPS standard will be applied on a "gateway" basis, at the time a LSE's commitment (build or buy) is proposed.
b. The standard will be applied to the reasonably projected emissions rate from the supply source over the term of the commitment
c. "Covered resources" are resources with a reasonably projected average annual capacity factor of 60% or greater.

**5. Which Power Sources are covered?**

**a.** Applied to utility owned **new generation, repowering or new/renewal contracts**
b. All new and renewal contracts and investments in "covered resources" of **five years or longer**
c. Applied to **baseload and intermediate or "shaping" facilities with annual average capacity factor of 60% or greater**
d. Size threshold:
--For **specified facilities (built or under contract): 25 MW or greater** delivered to the grid;
--For **unspecified resource/facilities under contract: all sizes**
e**.** Application to QFs addressed in legal briefs
f. Self-generation is covered (size threshold determined based on amount delivered to grid; cogeneration thermal load credit calculated, see below).
g. Renewables are covered, emissions factors can be demonstrated at the time of review (includes biomass, waste-to-energy, geothermal, etc.)
h. Reliability exemption considered on a case-by-case basis

**6. What is the Standard and How Determined?**

   a. Emissions standards based upon CCGT performance
      i. Higher standard for new facilities : high-performing new CCGT
      ii. Moderate standard for existing facilities and repowering – keyed to performance of existing CCGT fleet
      iii. Allowance for cogen thermal load

   b. Potential R&D exemption on a case-by-case basis (e.g., permit advanced coal facilities that have the capacity to capture and store carbon dioxide "safely and inexpensively" as described in the GHG Performance Standard Policy Statement?).

**7. How to apply the standard to units and contracts**

   a. For single unit specific contracts: applied on facility basis
   b. For multi-unit contracts: each covered unit must qualify
   c. Baseload renewable product with firming fossil (that qualifies as a "covered resource") -- applied to baseload blend average. If firming unit is unspecific impute appropriate emissions factor.
   d. Treatment of null renewable power? Not addressed at this juncture.
   e. Unspecified resource contracts: apply appropriate emissions factor. Choices are:
      i. WECC system average
      ii. Appropriate geographic average (e.g., NW is different from SW)
      iii. CEC "Net System Power" calculations
      iv. Default to coal emission rates

**8. Monitoring and Enforcement**

   a. CPUC gateway review with documentation and approval required prior to finalizing contract or commitment to construct

**9. Offsets, Safety Valves, and other flexibility devices**

   a. No offsets or market price safety valves
   b. Case-by-case "safety valve" upon application and CPUC review for reliability only.

### C. Workshop Participants Comments on the Staff Proposal (Days 2 and 3)

- The proposal should not apply to existing resources. (SCE, PG&E)

- The goals of the program are not clear. What are the risks that the CPUC is attempting to address? (Constellation)

- Not sure how this proceeding comports with the procurement proceeding. (SCE, Sempra)

- Not clear how to address multi-jurisdictional LSEs. (PacifiCorp)
- How will IOU new generation be addressed? (PG&E, IEP)
- Proposal needs to include language relevant to the delivery to the grid to address co-generation produced power. (EPUC)
- Baseload definition should be more aggressive. (GPI)
- Projections should be based on an average year. (PG&E)

## V. Data Needs (Day 3, continued)

The morning of day three continued the discussion of the staff proposal and modifications as described above. In the early afternoon, the discussion shifted to focus on high-level data that the CPUC needs to assess the essential impacts of an interim EPS. The following list of data was requested after which the workshop concluded. Responses to the assigned data requests are posted at www.cpuc.ca.gov/static/energy/electric/climate+change.

Based upon the responses provided to the service list, staff has made some modifications and updates to the original staff proposal. Specific discussion of findings is included in Section VI below.

At the workshop, the IOUs (PG&E, SDG&E, SCE) and other workshop participants agreed to prepare, and provide to the service list, the information/analysis on topics related to the threshold policy issue and implementation design considerations for an interim EPS, as follows:

1. The size of the potential IOU procurement needs that would be covered by an interim EPS. The IOUs and the CEC are working on a common format for this information and will be providing the format to staff by July 7. By July 11, both redacted (public) and unredacted versions of this information will be provided to staff. The intent is to provide to the service list as much publicly available data on this topic as possible.

2. Analysis around the definition of "covered resources:" What proportion of GHG emissions from long-term commitments would be excluded/included if the threshold for review is 60% average annual capacity factor vs. 50%, 70% or 80%? The IOUs will be providing this information to staff by July 11th.

3. Graph/Schematic of representative heat rates/emission rates for different types of facilities, for the purpose of considering the level of the "moderate" and "high" EPS thresholds for existing/new facilities under the staff Straw Proposal, or alterative approaches. The IOUs and other workshop participants agreed to coordinate on this document, due July 11 to staff.

4. Size of potential ESP procurement. SCE and AReM are working on this information that will be submitted to staff by July 14.

5. Emission factors for unspecified resources. CEC staff will provide the WECC regional emissions average, sub-region averages and the "net system" average figures to staff by July 11.

6. Potential new sources of power (new projects coming on line) proposed for potential sale to California IOUs. CEC, WRA, Constellation and PacifiCorp agreed to pull together the data available on this issue, and provide it to staff by July 11.

In addition, at the workshop several participants agreed to coordinate the development of the following information to present in their post-workshop comments (jointly, if possible):

a. How one would calculate the net emissions rates from renewables (GPI, PG&E, NRDC and others)

b. The formula for a cogeneration thermal credit calculation, and whether it is consistent with the CARB approach: (EPUC circulating to others before comments are due)

c. Protocol for assigning "covered resources" to California for multi-jurisdictional utilities and other implementation issues unique to multi-jurisdictional LSEs (PacifiCorp, WRA).

## VI. Post-Workshop Comments, Staff Discussion and Recommendations

Parties were directed to file post-workshop comments as described in Appendix E. This section summarizes those comments and identifies key outstanding issues. Each section concludes with a brief summary of staff recommendations on those issues. Rather than attempt to summarize each party's comments in full in this Report, staff will focus on areas of broad agreement, specific debate and/or concern, new recommendations for modification of the staff proposal that were not included in the discussion at the workshop, and other issues of key concern.

Eighteen parties provided comments on July 27, 2006. Those parties are:

- PG&E
- SDG&E and Southern California Gas Company (SoCalGas)
- SCE
- PacifiCorp
- LS Power
- Constellation
- Calpine
- PowerEx
- Independent Energy Producers Association (IEPA)
- Division of Ratepayer Advocates (DRA)
- NRDC/UCS/TURN (filing jointly)
- Center for Resource Solutions
- Alliance for Retail Energy Markets (AReM)

- Western Resource Advocates (WRA)
- Green Power Institute (GPI)
- San Francisco Community Power (SF Power)
- California Cogeneration Council (CCC)
- Cogeneration Association of California and the Energy Producers and Users Coalition (EPUC/CAC, filing jointly)

Key concerns and suggestions are identified below using the questions and format of the directions for post-workshop comments.

**A. Threshold Issue: Should the Commission adopt an interim EPS?**

**Q1 and Q2. Should the Commission adopt an interim EPS? Why or why not? Do you generally support the "gateway" approach to the standard proposed in the staff proposal?**

Parties' perspectives varied significantly on this issue. Several parties supported the interim EPS as described in the staff proposal primarily because 1) it sends a clear signal and regulatory certainty regarding long-term contract requirements, and 2) given the existing procurement requirements, the proposed EPS is unlikely to impose significant burden upon LSEs to comply.

Other parties opposed the concept of an EPS on the grounds that it would largely be largely duplicative of existing CPUC policies such as the Renewable Portfolio Standard (RPS), Energy Efficiency (EE), and the carbon adder. It was unclear if the performance standard would substantively change LSE behavior or the LSE emissions footprint, in which case it seems to be an unnecessary program.

**B. Implementation/Design**

**Q3. Assuming that the Commission decides to proceed with an interim EPS, what should be the major design principles/objectives for such a standard?**

Most parties agreed with the top four priorities included in the straw proposal, and provided only minor language modifications. Those priorities are:

1) Prevent backsliding and commitments that will make future GHG reductions more difficult
2) Minimize costs to ratepayers and minimize the risk of long-term commitments that will raise the cost of future compliance costs
3) Reliability:
    i) short-term: do not force shutdown of essential facilities
    ii) long-term: consider risks of relying on high emitting resources.
    iii) Administrative simplicity

Other recommendations included specific provisions for LSEs, encouragement of new technologies, incentives to energy efficiency and renewable energy, minimization of gaming, and provisions for allowances for cogeneration facilities. Many of these suggestions did not necessarily fit with the "goals" section and were better suited for consideration in timing and implementation of the program.

The issue of administrative and regulatory certainty was also highlighted. That modification has been included in staff's updated proposal below.

**Q4. Please discuss the relative advantages of the "gateway" approach to an EPS, and the potential disadvantages. If you propose an alternative, please describe.**

While not all parties support the concept of an EPS, all parties viewed a gateway screen approach as being the most effective approach if an EPS were to be implemented. No parties proposed an alternative approach to administration of the program.

The principal reasons that parties supported the gateway approach are because it minimizes contract approval uncertainty, sends clear signals regarding compliance, and does not require ongoing administrative oversight and therefore is relatively straightforward to manage. Staff supports a "gateway" standard for these reasons.

**Q5. The Staff Straw Proposal applies the EPS to new commitments (construction, repowering, and new or renewal contracts).** *Please comment on whether you support the Staff Straw Proposal on this issue, indicating your views on the relative advantages and disadvantages of applying the EPS to both new and existing generation facilities (under new commitments). Relate your response to this question to the design priorities you articulate under question #3 above.*

Many parties argued that the EPS should apply to new commitments with new facilities only. Others agreed it should apply to "new" facilities but also included repowered facilities as "new" and therefore subject to the EPS. Under this approach, resources currently under contract with an LSE would not be subject to the EPS, even if that contract was to come up for renewal while the EPS is in place. Most of these parties argued that if the CPUC is most concerned with preventing "backsliding" on emissions prior to a cap being implemented, then existing resources should not be subject to the EPS as they are part of the status quo.

A third group of parties argued that all new commitments, including renewal of existing contracts as well as new construction, repowering, and new contracts should be subject to the EPS. Since the EPS is administered on a contract by contract basis using the gateway approach, it is not prudent for the CPUC to "grandfather" in any resources under current contract that would be subject to renewal during the EPS. The Rule should not create an incentive for LSEs to renew existing contracts, rather than making resource decisions based upon the broad portfolio of all available resources. An artificial incentive to renew existing entitlements could arise if the EPS were limited in scope to new resources only.

Staff supports the third position and recommends that all new or renewal contracts and/or commitments with resources, including existing, repowered, and new facilities, should be subject to the EPS. A decision to renew a contract commits California's LSEs and ratepayers to its cost and emissions profile just as a decision to enter into a new contract with a new facility.

**Q6. Should the EPS cover only commitments (construction or contracts) of five years or longer as the workshop participants generally agreed?** *There was also general agreement among workshop participants that if adopted, an interim EPS should cover commitments (construction or contracts) five years or longer, which is also reflected in the Staff Straw Proposal. Do you agree? Why or why not? How does this design parameter achieve (or not achieve) the priorities you have identified under question #3 above?*

All of the parties except for DRA supported the 5 year or longer commitment cutoff as it comports with the CPUC current long-term procurement plans and with the spirit of the CPUC's Performance Standard Policy Statement.

DRA proposed inclusion of short-term contracts (and contracts smaller than 25MW) as peaking and shaping resources are often higher emitting than baseload resources.

Staff has been directed to recommend an interim program that can be implemented in the near-term. Discussion at the workshop, including that of CPUC staff assigned to procurement activities, and subsequent comment by the majority of parties indicates that inclusion of short-term contracts would be burdensome to manage in the near-term and could raise reliability issues as well. The proposed inclusion of contracts of 5 years or greater avoids long-term commitments to high-emitting resources, and provides the clearest path to implementation while mitigating reliability issues associated with peak and seasonal demand.

**Q7. Another major design issue discussed at workshops was what the Commission should look at (contract or facility operation) in determining whether the EPS applies. In particular, should the Commission (1) look at the operation of the facility underlying a contract, or (2) only to the amount/product contracted for by the LSE?** *The Staff Straw Proposal takes the approach that, for specified contracts, the Commission should look at the expected operation and emissions of the facility, rather than just the contracted amount. Please comment on the advantages and disadvantages of these two alternative approaches, and your position on this issue.*

**Specified Contracts:**
For specified contracts and commitments, several arguments emerged. PG&E argued that the screen should be applied to the resources procured under the contracts and not the entire facility or facilities that happen to be owned by the contracting party. SDG&E/SoCalGas, SCE, and Constellation further argued that it would be burdensome to identify the operations of the underlying resource.

Alternatively, other parties supported inclusion of facility operations as part of the gateway review. PacifiCorp and IEPA recommended that the facility's average emission rate be used as the appropriate emissions factor in the case of specified contracts. Calpine, DRA, NRDC/TURN/UCS supported review of the underlying facility as well.

The initial staff proposal recommended that specified long-term contracts and commitments of 25MW or greater delivered to the grid with a capacity factor of 60% or greater be required to go through the gateway screen. At that point, the emissions factor for the underlying facilities would be applied.

Based upon discussion at the workshop and post-workshop comments filed, staff is not persuaded to modify this approach. For specified contracts, the capacity factor, average heat rate, and emissions factor of the underlying facility(s) supplying power should be readily available as operators are required to provide this information to multiple regulatory agencies such as the US EPA and CA Air Districts. Staff agrees with PG&E's point that the screen be applied to the resources under contract to provide energy to a LSE, rather than the entire facility(s) that happen to be owned by a contracting party.

**Unspecified contracts:**
For unspecified contracts, the IOUs argue that the requirement to include information about an underlying facility's operation would be administratively burdensome, and in many cases impossible, as the facility under contract would either not be known or facility operations would be proprietary information and not likely to be disclosed to a contracting LSE. LS Power and Constellation believe that only new resources should be included in the EPS in order to simplify the reporting process.

PacifiCorp argues that unspecified contracts should be required to have an emissions rate imputed on a MWh basis. Other parties (NRDC/TURN/UCS, DRA) support looking at the underlying resource in order to ensure that LSEs are not entering small contracts with large high emitting baseload resources, and to limit gaming of the system based upon size of contract.

Under the initial staff proposal, all unspecified contracts would be required to go through the gateway screen and, to the extent possible, the underlying facility(s) operations would be estimated and the emissions factor for unspecified contracts would be applied.

Based upon parties' comments, it is evident that it would be burdensome and in many cases infeasible to estimate the operations of unspecified facilities. The staff proposal is modified to require review of unspecified contracts based upon the size of the commitment, rather than the size of the underlying facility. In cases where it is known that the underlying facility's capacity factor is less than 60%, the gateway screen would not apply. If the capacity factor is either unknown, or known to be 60% or greater, the gateway screen would apply. For unspecified contracts, contract emissions rates would be imputed , from the best available information, as discussed at Q 15 below. However, staff does recognize the potential gaming issues raised by DRA and NRDC/TURN/UCS and makes the following recommendation under "All commitments" below to address potential "slicing and dicing" of contracts, or other evasive procurement activities that may be undertaken to avoid an EPS screen.

**All commitments (specified and unspecified):**
The focus of the EPS program is on power supply reliance and financial commitments by California LSEs, rather than on the characteristics of facilities that may or may not be located in the State. Thus, we recommend that the 25 MW threshold apply to the contract or other commitment made by a LSE, rather than to the total size of the generating facilities involved.

At the same time, the Rule should not create incentives for LSEs to avoid the substantive standard simply through contractual "gaming" – that is, by entering into multiple smaller contracts, each of which may be below the jurisdictional thresholds, but which together amount to a significant long-term commitment of LSE resources. To that end, staff recommends that a series of related contracts with the same supplier, likely resource, or known facility, or a series of related or similar contracts with separate sources should be considered as a single commitment in size, capacity factor, and duration.[6]

Such multiple contract activities must be disclosed by the utilities to the CPUC in order to avoid "slicing and dicing" of large contracts to avoid or manipulate the gateway screening process for the performance standard review. Utilities who do not disclose such activites will be considered in violation of the performance and subject to penalty and enforcement mechanisms.

We recognize that some professional judgment is required to determine when certain contractual commitments are "related" or "similar" so as to trigger review as a single commitment. However this is a common enough problem in environmental regulation and utility prior review programs, and we expect a professional rule of reasonableness to govern its application here. LSEs that are in doubt as to the application of the Rule to new long-term commitments can disclose their contracting patterns to the Commission and seek a jurisdictional determination under the Rule.

**Q8. There was general agreement during the workshop that an interim EPS should not apply to peaking facilities or resources expected to operate relatively few hours during the year. Accordingly, the Staff Straw Proposal uses a definition for "covered resources" as those with an annual average capacity factor of 60% or greater, intending to cover resources operating as year-round base load and high-use intermediate and shaping facilities.** *Do you believe that this definition of covered resources is appropriate? In responding, please address the following:*

[6] Similar and related commitments should be considered cumulatively with respect to size, capacity factor, and duration. For example, two contracts with a baseload facility, each for 40% of the hours of the year, must be seen as the equivalent of a single commitment with an expected capacity factor of 80%. A contract for a four-year term, linked to a contract for the following 4 years, must be seen as a single commitment for eight years.

**a. What types of resources do you believe the EPS should cover and whether you believe the straw proposal capacity factor (60% or greater) metric to define a covered resource will capture those resources.**

Most parties recommended that the EPS cover all baseload resources defined as those resources with a 60% or greater capacity factor (c.f.). Parties that supported a 60% c.f. referenced data submitted by the IOUs in responses to data questions 1 and 2 ("Size of potential IOU procurement needs that would be covered by an EPS" and "Portion of GHG emissions from long-term commitments that would be included at various capacity factors"). Data submitted for questions 1 and 2 illustrated that a 60% c.f. captures 78% of the IOUs' 2012 open procurement need and would capture 72% of CO2 emissions.

Lowering the threshold capacity factor to 40-50%, (as suggested by GPI and DRA) would result in additional emissions captured, but these reductions would not be as significant as the incremental step-down from 70% c.f. to 60% c.f., which represents the largest delta with regards to emissions reductions at the different capacity factors. For example, a 50% capacity factor would affect an additional 5% of procurement and capture an additional 6% of CO2 emissions. Comparatively, the move from 70% c.f. to 60% c.f. affects an additional 13% of procurement and captures 13% more emissions.

Based on the data and comments, staff recommends a 60% capacity factor as a reasonable threshold. This approach captures the large majority of emissions from potentially emitting resources, while minimizing administrative burdens and potential interference with resources needed to meet peak loads.

**b. Present an alternative metric(s) for defining "covered resources" that you recommend, if you do not support the Staff Straw Proposal definition.**

GPI and DRA advocated for a lower than 60% capacity factor (40%-50%) to ensure that all high emitting intermediate and shaping facilities are covered.

See discussion and staff recommendation above (Q8.a.)

**c. Whether (and if so, how) the EPS should incorporate a research and development exemption for advanced coal or other technologies.**

Some parties suggested an R&D exemption for advanced coal technologies and specifically one for IGCC carbon capture-ready technology (SCE, PacifiCorp). SDG&E suggested a more general, non-technology specific R&D exemption that could be applied on a case-by-case basis. Other parties argued that no exemptions should be granted and that all resources should be required to meet the EPS (Calpine, DRA, NRDC, TURN, UCS, GPI).

Based on parties' comments, staff recommends a R&D exemption that could be granted by the CPUC on a case-by-case basis for higher-emitting facilities upon demonstration that the commitment in question will make a significant contribution to developing a lower-emitting resource mix in the future. One example might be an advanced coal facility that has an equal or better emission rate than the estimated IGCC average heat rate and emissions, and that has or will have within a reasonable period of time the capacity and an existing plan to capture and store carbon dioxide as described in the GHG Performance Standard Policy Statement.

**Q9. Another design issue discussed at the workshop was how the EPS should apply to specified contracts with more than one underlying covered resource (new or existing): Should the Commission apply the EPS to the "blend" of the resources/units, or require that each covered resource meet the EPS individually?**

**Under the Staff Straw Proposal, each individual covered resource must meet the EPS, with the exception of a renewable contract firmed with a non-renewable resource. In that case, the blend of the two must meet the EPS, rather than the individual resources/units.**

*Do you agree with this approach? Why or why not? In your response, present your view of the relative advantages and disadvantages of the alternate approaches, and discuss your recommendation in the context of your answer on design priorities under Question #3.*

Many parties supported the staff proposal recommendation. However, a language nuance was raised by several parties. The staff proposal requires each covered resource to be in compliance with an EPS. Parties communicated difficulty in determining the activities of specific units that may be operating at a multi-unit facility or plant. SDG&E suggests in these cases to use the information available at the plant level, and to allow for exceptions where necessary.

Regarding renewable power firmed with a non-renewable resource, PG&E felt strongly that any RPS eligible resource, regardless of any associated firming resources, should be deemed in compliance with the EPS.

For multi-unit contracts where specific unit operations are unknown, staff recommends modifying the proposal to allow for facility/plant average as SDG&E suggests. In the case of renewables with covered firming resources, staff recommends no change to the straw proposal-- the resource blend must meet the EPS.

**Q10. In the context of the Staff Straw Proposal, how should the Commission treat partial contracts under the proposed EPS?** *An example discussed at the workshop was a "summer product" contract for power from a specified coal plant. For partial contracts, should the Commission look at how the facility is operating during the duration of the contract commitment, at the MWhs being purchased relative to the full year of facility operations, or consider other approaches? Would your proposed treatment of partial contracts result in an exemption under the 60% capacity factor rule, even if that underlying facility would be a "covered resource" under average annual operation? Why or why not?*

Most parties recommend that, similar to Q7, the contract be subject to the EPS rather than the underlying facility. Many parties expressed concern about inclusion of short-term shaping resources in the EPS, as these resources are required for seasonal reliability and are not baseload resources.

NRDC/TURN/UCS supports inclusion of these contracts on the basis of the underlying resource.

Staff recommends that partial-year contracts for shaping resources that have less than a 60% capacity factor on an average annual basis not be covered by the EPS because of the seasonal reliability issues that they address. It is important to note that this distinction is based upon the size and expected capacity factor of the commitment (and thus its GHG emissions), not its name or degree of dispatchability.[7] However, the multiple contract provisions discussed above in Q7 would apply. LSEs are not allowed to enter into multiple small or shaping contracts in order to avoid the EPS gateway screen.

**Q11. The Staff Straw Proposal allows for an exemption from the standard for specified units of 25 MW or smaller, based on the size of the facility under construction or providing power under a contract. However, there would be no size exemption for unspecified contracts of any size. In commenting on this aspect of the Straw Proposal, please address the following:**

**a) The MW level of the "small unit" exemption under this proposal. Do you support this exemption as proposed? Would you propose a different size exemption level and/or one specifically tied to projects qualifying under the self-generation incentives program? No exemption? Why or why not?**

The majority of parties supported inclusion of resources 25MW and greater for specified units, on the basis of current long-term contract requirements, compatibility with the Air Districts and US EPA regulations, and because it comports with the Northeastern Regional Greenhouse Gas Initiative (RGGI) emissions cap program.

In addition, many parties argued that all contracts, including unspecified, be subject to the 25MW or greater threshold in order to maintain consistency and to minimize administrative complexity (PG&E, SCE, SDG&E, IEPA, CCC, EPAC, CAC).

NRDC/TURN/UCS, DRA, and in some cases GPI, support a 5MW cutoff for compatibility with the self-generation incentive program (SGIP), and to ensure inclusion of high emitting resources associated with small contracts. Further NRDC/TURN/UCS suggests that no size exemption be given for unspecified contracts since it is impossible to identify the resources behind these contracts.

Staff recommends no change to the current proposal for specified contracts, as it is not persuaded that significant benefits would result from lowering the size threshold for review.

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[7] Thus, acquiring a resource for "shaping" purposes, or because it can follow load does not for these reasons alone exempt it from application of the gateway criteria recommended in this Report.

For unspecified contracts, staff modifies the initial proposal to recommend a 25MW or greater threshold for contracts and commitments for the screening process in order to focus on long-term contracts, create consistency, and mitigate administrative complexity across the screening process. Parties did not present persuasive arguments to support a requirement that all unspecified contracts should go through the screening process.

The interim EPS is meant to be implemented in the near-term and mitigate administrative complexity where possible. Being that the program is intended to focus on long-term baseload contracts, and we are adding provisions for multiple contracts to prevent "slicing and dicing" of contracts, staff recommends that 25MW be the cutoff for both specified and unspecified commitments as it is most consistent with current Commission, state, and other jurisdiction's emissions policies.

**b) Basing the exemption on MWs delivered to the grid. In determining eligibility for the size exemption, the Staff Straw Proposal would subtract out self-generated power that was not delivered to the grid.**
  **i) Please indicate whether you agree with this approach to determining the size exemption, why or why not?**
  **ii) If the Commission adopts this approach, what type of information (and source of data) would need to be presented for the Commission to determine the amount of expected self-generation to subtract from the unit size?**

The majority of parties commenting on this matter support the staff proposal, and the calculation proposed for crediting cogeneration facilities.

NRDC/TURN/EPS suggests that the EPS apply to all of the emissions associated with a LSE's contracts, even if the energy is used on-site as GHGs are emitted either way.

Staff was not persuaded to modify the current proposal, and maintains its recommendation that self-generation contracts be evaluated based upon the electricity delivered to the grid. However, as discussed in greater detail in Q13, a thermal credit for applicable self-generation resources will be determined on a case by case basis.

**c) Basing the exemption on the size of the unit being constructed or underlying a unit-specified contract, rather than the size of the contract. Please discuss the relative advantages and disadvantages of these alternate approaches to a size exemption, and indicate which you would recommend, should the Commission determine that a size exemption would be appropriate. (You may refer to your answer to the related Question 7, as appropriate).**

As discussed in Q7 and Q11a, after review of the comments, staff recommends that specified long-term contracts and commitments of 25MW or greater delivered to the grid be required to go through the gateway screen. The screen would apply to the committed underlying resource and its average emissions factor. For unspecified contracts, staff recommends the emissions factor for unspecified contracts be imputed based upon the contract size rather than attempting to identify the emission rates of the underlying facility or facilities. We realize that a more detailed emissions tracking system will be of great use to LSEs in the context of a load-based cap-and-trade system, but are persuaded that individual facility emissions rates may not be readily available to LSEs for unspecified contracts at this time.

For specified contracts, DRA and NRDC/TURN/UCS arguments to lower the size threshold did not substantiate the benefits to doing so. The vast majority of commenting parties supported the 25MW or greater threshold as it comports with current CPUC, state, federal, and regional emissions policies, and comports with the interim EPS focus on baseload resources.

For unspecified contracts, parties persuasively argued that information about underlying resources would be difficult, if not impossible, to ascertain at the present time. Because of this administrative impediment, staff recommended in Q7 to modify the unspecified rule to trigger the gateway screen.

**d) No size exemption for any unspecified contracts. Do you support this approach? Why or why not?**

Most parties did not comment on this issue. SCE recommends the same size exemption for specified and unspecified contracts[8]. LS Power believes that it is unlikely that new non-unit specific contracts will be entered into during the period of the interim EPS, so views this as a non-issue. IEPA believes that no exemptions should be made for unspecified contracts. NRDC/TURN/UCS supports the staff proposal recommendation to require all long-term unspecified contracts of any size to be covered by the EPS.

For the reasons discussed above (see discussion at Q7), staff recommends that the EPS apply to the size of the commitment involved rather than to the size of the underlying facility or facilities that may be supporting the contract. We recommend setting the size exemption for unspecified contracts at the same level as for commitments with specified facilities (i.e. 25MWs or greater). If the EPS is designed to look at the emissions associated with a contract or commitment, then it is reasonable, and easier to administer, if the size of contract covered under the EPS is the same for both specified and unspecified resources. Provisions to aggregate multiple contracts will be needed in order to avoid contract gaming for jurisdictional purposes (see discussion at Q7).

**Q12. Under the Staff Straw Proposal, the Commission would develop two separate standards for covered resources: 1) a "moderate" EPS to apply to existing resources and repowering and 2) a "high" EPS to apply to new resources. Both would be based on the performance of a combined-cycle gas turbine (CCGT). Please address the following questions in your comments on this approach:**

[8] "Specified contracts" are contracts that specify the generating units or facility providing the power, while "unspecified contracts" are not linked to any particular generating resource.

*a. Do you agree in concept with a dual standard as outlined in the Staff Straw Proposal, why or why not?*
*b. If the Commission adopted this approach, what performance standard do you recommend for the "moderate" and "high" EPS? Express your answer in terms of heat rates as a proxy for GHG emission rates. Explain why you chose these levels, and the source of data/calculations you used to develop them.*

*c. If instead you recommend a single EPS based on the performance of a CCGT for all new commitments (whether to new resources, existing or repowered facilities), provide your recommended performance standard (expressed as a heat rate), explain why you chose this level, and the source of data/calculations you used to develop it.*

*d. In responding to b. and c. above, be specific as to how you developed your CCGT reference standard and the data sources/calculations used. For example, did you base it on the expected performance of a modern CCGT newly placed in service, or at the end of its useful life, or an average of emissions from existing CCGTs, or another approach?*

*e. If you have alternate or additional recommendations for the EPS standard and calculation, please submit them.*

Data submitted by a working group composed of the IOUs and other parties in response to data question 3: "What are the representative heat rates/emission rates for different types of facilities?" provided the background for parties' responses to Q12. The first worksheet, "Heat rate and emissions w/vintages," shows that emissions for those CCGT plants built from 1980 to present range 800-1020 lbs $CO_2$ / MWh. Within this range, there are no significant difference among vintages. In contrast, for other types of gas plants, such as single turbine, the range extends upwards to 1250 lbs $CO_2$/MWh.

Since both existing and new CCGTs perform at nearly the same levels, and since there are strong economic incentives for new gas facilities to perform efficiently, staff concludes that it is not necessary to impose a stringent standard for "new" facilities as opposed to existing units. New or repowered CCGT plants are likely to have a low emissions profile in order to be competitive. Most parties suggested one EPS standard instead of a moderate and high standard. Two reasons were given: administrative ease (LS Power, Constellation) and the ability of one standard to sufficiently incorporate all existing CCGT plants while discouraging less clean facilities (NRDC/TURN/UCS).

Based upon comments and the data presented, staff does not see the need for two EPS standards.

The second worksheet, "Spreadsheet of existing emissions rates" provides emissions data from EPA's Continuous Emissions Monitoring System (CEMS) on existing CA gas plants. This spreadsheet details that the range of emissions from CA gas plants operating at 60% capacity factor or greater is between 794 and 1,006 lbs CO2/MWh with an average of 856 lbs CO2/MWh.

Multiple parties proposed 1,100 lbs CO2/MWh as the single standard (SDG&E, NRDC/TURN/UCS, GPI). SCE proposed a high standard of 1,000 lbs CO2/MWh and a moderate standard of 1,400 lbs CO2/MWh.

After consideration of the data and suggestions proposed by parties, staff recommends a single standard, applicable to new and existing plants and contracts, of 1,000 lbs CO2/MWh. This standard allows for high performing existing CCGTs to qualify and is significantly above the average emissions reported for gas plants within and outside of the state.

**Q13. There was general agreement at the workshop that the Commission should allow credit for cogeneration thermal load when applying the EPS to covered resources. This is reflected in the Staff Straw Proposal. Do you agree with this approach, why or why not?**

*If you have developed a specific formula for the calculation of such a credit, please provide it in an attachment to your post-workshop comments, or in a separate joint submittal at the same time (if you are joining in with other parties on this issue). Indicate whether it is consistent with methods used to credit thermal loads in other emissions regulations for cogeneration facilities, either in California or elsewhere.*

As part of the post-workshop data requests, EPUC/CAC submitted the following formula for calculation of a revised emissions rate for cogen facilities that reflects credit for useful thermal energy: Emission Rate = Total GHG Emissions / kWh of Electricity + Btu Thermal Energy (converted to kWh). This calculation was also supported by CCC and DRA.

Concerns were expressed by some parties that the above calculation overstates useful thermal energy. Alternatives to the calculation include:

1. Apply a discount factor such as 50% to the formula to correct for the assumption that all thermal energy is convertible to electricity (SCE);
2. On a case-by-case basis, assume thermal application separate from electricity production by calculating CO2 savings from avoided boiler use (assuming 80% boiler efficiency) and subtracting saved lbs CO2 / kWh from standard facility lbs CO2 /kWh.
3. Although not providing a specific alternative, NRDC/TURN/UCS advocated for a methodology to be applied on a case-by-case basis that accounts for useful, and not only theoretical thermal energy.

While staff concludes that it is appropriate, and is consistent with the goals of a GHG reduction policy, to grant credits for the thermal side of a co-generation facility, we do not recommend a particular formula for calculating that credit at this time. Co-generation facilities' operations are often unique and specific to particular on-site activities. Based on the parties' responses and discussion at the workshop, we recommend that cogeneration facilities be permitted to apply for emissions credit for their thermal load on a case-by-case basis if they do not meet the standard on their own.

Such credits should reflect the useful, and not just theoretical, thermal energy load and will need to be calculated on a case-by-case basis. We recognize that a more in-depth review of this topic may be useful in the context of a permanent cap-and-trade program, but it may not be needed solely for the purposes of the interim EPS.

**Q14. Do you have a position on how to calculate the net emission rates from renewables (e.g., for waste-to-energy, geothermal resources) for the purpose of applying the EPS?** *If so, please present your views either in your individual post-workshop comments or jointly with other interested parties at the same time.*

Most parties commenting suggested assigning a zero emissions rates for all renewables, including those from biogenic sources (PGE, SDG&E, DRA, GPI, IEP). NRDC/TURN/UCS suggested net emissions be considered for biogenics and zero emissions rate for other renewables.

The rationale provided by GPI in its recommendation for assignment of zero emissions to all renewables including biogenics, is that although biogenic renewables (biomass and biogas generators) have higher GHG emissions from the stack than CCGT, when net emissions are properly accounted for, these resources reduce the net emissions associated with the alternative disposal of these same materials and eventually have lower emissions than CCGT plants.

Based on parties' comments, including consideration of the EPS goal of administrative ease, staff recommends that all renewables, including those from biogenic sources, be assigned an emissions factor of zero. This issue is likely to require further analysis in the context of a comprehensive cap-and-trade program, where even low emission rates will require the retirement of credits, but it is not necessary to resolve these questions in this phase of the docket.

**Q15. There was discussion during the workshop on how to address unspecified contracts, i.e., what imputed emissions factor to use. The following alternatives were identified:**

*a. Western Energy Coordinating Council (WECC) system average;*
*b. Appropriate geographic average (e.g., Northwest purchases represent different resources than purchases from the Southwest);*
*c. California Energy Commission (CEC) "Net System Power" calculations;*
*d. Default to coal emission rates.*

*Please discuss your recommended approach, and why. Be as specific as possible as to the source of the data (or specific numbers) you would use for this purpose.*

The CEC provided data on the underlying fuel mix for imputation factors(a)-(c) above. Emissions rates for (d). (coal) were provided as part of the emissions data in data question 3. Although imputed emissions rates were not provided for these options per se, the provision of the underlying fuel mix sheds sufficient light on whether such an emissions rate would pass a CCGT-based EPS.

Parties had varying opinions on the appropriate imputed emissions factor. PG&E advocated for a geographic average that would distinguish among WECC sub-regions. SDG&E, PacifiCorp, and IEP suggested use of the CEC Net System Power calculation. NRDC /TURN/UCS recommended assignment of a coal emissions factor in order to deter LSEs and suppliers from reclassifying coal contracts as unspecified power. DRA also suggested that unspecified power should not be considered as meeting the EPS.

Other parties disagreed with the use of any imputed emissions factor since it is:
1) unlikely unspecified contracts will make up a significant portion of long-term contracts anyway (Constellation), and 2) an imputed factor automatically sets up an unproductive binary scheme in which all or none of the resources pass (SCE).

In looking at alternatives (a)-(d) above, staff characterizes them as following:

a) WECC system average: Incorporates all generation activities throughout the western region.
b) WECC geographic average: Computes an emissions factor for all generation activities in various regions of the WECC system such as the NW, SW, etc.
c) CEC calculated " CA Net System Power Average": This average accounts for and weights by region the differing emissions factors from unclaimed resources generated in CA and imported to CA.
d) Coal emissions factor: would be based upon representative emissions from coal generation.

Based upon review of the data and parties comments, staff finds that the WECC system average is generally not reflective of CA activities or market. Using this average would be somewhat arbitrary as staff does not believe that it is specific enough to load served in CA.

Similarly, the WECC sub-regional geographic averages suffer from the same shortfalls and broad sweeps, and would further penalize and reward LSEs differently based upon the major geographic source of their imported system power, which is largely a function of the location of their service territory within California. While we recognize that a different approach may be necessary for the cap-and-trade program, staff is uncomfortable making a geographic assignment that would set up different regional emissions factors for the purpose of the phase 1 EPS program.

Regarding the use of coal as a proxy emissions factor, staff does not view this as a reasonable approach. While it is simple to administer, it is not an accurate reflection of the characteristics of all unspecified resources.

Staff acknowledges the concern raised by some parties that LSEs will be inclined to enter into unspecified contracts with high emitting resources in order to circumvent the EPS by having a possible lower emissions rate assigned to that resource. Based upon the comments, especially the assertion that long-term contracts with unspecified resources are a small fraction of the incremental power supply, staff does not anticipate this being a substantial issue. Staff will monitor contracting patterns and behaviors to ensure they do not change for this reason. In addition, staff also has recommended provisions for multiple contracts (see Q7.) to avoid "slicing and dicing" of larger contracts.

The CEC's CA Net System Power Average is currently used by the IOUs for power content labeling purposes. The Average takes into account the geographic origins (in-state and imported) of all of the State's unclaimed power sources, and assigns weights to the relevant emissions factors to create a single factor, that can be applied equally across all CA LSEs. Of the options, this Average and its imputed emission factor is the most representative of CA's unclaimed energy mix. Staff views this to be the superior of the options and modifies its proposal to recommend its use as it is the most comprehensive and accurate of the options. Staff notes that the CEC is currently refining the methodology for the net system power mix and expects to have an updated version this fall. The CPUC should consider this methodology as well once complete.

**Q16. The Staff Straw Proposal does not include offsets or market price safety valves under the interim EPS, but does provide for a case-by-case reliability "safety valve" review by the Commission.** *Please comment on this aspect of the proposal, and provide your recommendations.*

In their responses to this question, parties presented a number of scenarios that might trigger a "safety valve" response or an exemption such as:

- ability to meet reliability standards established by CAISO, unless they can be met while also meeting the EPS (PG&E, Constellation).
- any unforeseen circumstances (SDG&E and SoCalGas)
- investment in advanced coal technologies to support the Western Governor's Conference recommendations (SDG&E and SoCalGas)
- cost issues that could trigger an "economic safety valve" (SCE)
- Jurisdictional issues (PacifiCorp)

In addition, several respondents commented on the use of offsets in the EPS program. LS Power and EPUC/CAC generally support offsets as part of an EPS program. Others recommended coupling offsets with a "safety valve" (Constellation).

Most parties did not support the inclusion of offsets at this time. Calpine viewed them as not fitting with the concept of an EPS program and anticipated unnecessary delays in implementation if offsets were to be included. Constellation and IEP also did not see this fitting with an interim EPS, and stated that they might be more applicable to a cap program. NRDC/TURN/UCS generally do not support the use of offsets and safety valves with the program.

Staff recommends no changes to the current staff proposal. In the current proposal, exemptions can be made based upon reliability at the discretion of the Commission. In order to implement an interim program in the near-term, we recommend not including provisions for a safety valve or offsets as part of the initial program as both of these issues would require significant up front analysis and ongoing monitoring. These issues are best addressed as part of phase 2 of this proceeding focusing on design and implementation of a load based cap.

**Q17. From a policy perspective, please discuss whether energy service providers, qualifying facilities (QFs) and other jurisdictional load-serving entities (LSEs), including multi-jurisdictional utilities, should be subject to an interim EPS along with PG&E, SCE and SDG&E, should the Commission decide to adopt one.** *Limit your comments to policy considerations, rather than legal argument.*

*If you have considered the issue of how the Commission would apply an interim EPS to multi-jurisdictional utilities, please present a protocol for allocating emissions among resources serving multiple states with your post-workshop comments.*

Many respondents, including all three IOUs, GPI, NRDC/TURN/UCS, IEP, argued that all CPUC jurisdictional LSEs should be included in order to ensure uniformity, consistency and mitigate competitive or cost disadvantage among LSEs. They also identified leakage and shuffling of resources as a potential result of limiting the EPS to IOUs. More broadly, many observed that an EPS program should ideally apply to all LSEs procuring and supplying electricity resources within the State of California. For multi-jurisdictional LSE's, PacifiCorp recommends developing a methodology that takes into account their particular circumstances. Many of the ESPs commenting requested that if required to participate, a process be developed to comport with their existing reporting requirements to the Commission.

EPUC/CAC and Constellation proposed exempting co-generation QF's "so as not to discourage their development." Alternatively, their emissions should only be included to the extent they deliver energy to the LSEs. Calpine suggested that QF's be included, but that the EPS take into account their useful thermal output (converted to an equivalent MWh number) when calculating GHG emissions for purposes of EPS compliance. Such an approach would ensure that the benefits associated with the increased efficiencies of employing cogeneration technology are appropriately recognized.

The issue of cogeneration is addressed in more detail in Q13.

Staff recommends that the EPS be applicable to all of the CPUC jurisdictional LSEs. IOUs will be subject to the gateway screen. As discussed in the staff proposal, the Commission will develop a filing/review process for the ESPs that comports with their current reporting processes. Regarding MJUs, staff recommends modifying the staff proposal to develop a filing/approval process for multi-jurisdictional utilities (MJUs), including a protocol for allocating emissions among resources serving multiple states. Provided that the principal objectives of the EPS are met – especially, avoiding major new commitments that would tie California electric consumers to high-emission resources over the long term -- consideration should be given to MJUs that have prior approvals from other jurisdictions for integrated resource plans (IRP) that include adequate provisions for climate change.

**Q18. If the Commission adopted an interim gateway EPS modeled after the Staff Straw Proposal, what documentation should it require "at the gate" with respect to 1) meeting the small size exemption, including amount of power delivered to the grid (for self-generation), 2) demonstrating whether the new commitment meets the "covered resource" definition or not, 3) claiming the cogeneration thermal load credit and 3) other requirements of the EPS?**

*Should there also be compliance requirements under this gateway approach (e.g., with respect to unspecified contracts), and if so, what should they be?*

Respondents each had specific suggestions, but generally advised that the documentation required for the emissions factors of specified resources could be derived from information submitted by the LSEs during the contract and application processes, including data submitted to FERC and per CEQA. Several suggestions were made for obtaining additional information where necessary such as testimony during the New Resources review process or verification by an independent third party.

Staff recommends using independently verified emissions data, such as the sources described above, in estimating the emissions associated with a contract. At this time, staff does not have a particular recommendation for a specific source or sources that should be used given that it appears that relevant data could be collected from numerous objective sources, including the California Climate Action Registry (CCAR).

**Q19. Staff Straw Proposal raises the issue of how to attribute emissions factors to renewable resources that have sold off their renewable energy credits (RECs) (e.g., to municipal utilities) for the purpose of applying the EPS.** *There was some discussion of this "null power" issue at the workshop. Options discussed included imputing an emissions rate from the WECC region or from the region where the renewable power was located, or using the CEC's "net system power" calculation as a default emissions rate. If you have a recommendation on this issue, please provide it in your comments.*

This issue solicited a fair amount of debate at the workshop and in comments. General recommendations provided by parties who provided written comments on this issue included: 1) allow all renewables regardless of REC status to be treated as renewable power (GPI, DRA), or 2) treatment of renewable power should mirror the RPS policy which requires a transfer of all "Renewable Attributes" to the purchasing LSE, and therefore null renewable power should not be treated as a renewable resource.

Parties who recommended that null renewable contracts be treated as devoid of renewable attributes also recommended that the null power should be considered "an unspecified resource" and treated as such (Constellation, PacifiCorp, SCE, IEP, CRS).

While staff wishes to support renewable development and contracts, we also want to ensure that RECs and REC markets continue to maintain their validity. When a REC is sold to a third party, the expectation is that the attributes of the renewable power come with that purchase. Allowing renewable power that has been stripped of its RECs to be treated as a renewable purchase for the purpose of meeting policy goals in California would undercut the integrity and essential point of a REC market. For that reason, we recommend that null renewable resources be treated as an unspecified or system power contract, and be subject to the same emissions factor as unspecified contracts.[9] As discussed under Q 15 above, for the purposes of meeting the EPS, that emissions rate would be the CEC's Net System Power Average.

### C. Revised Staff Proposal for an Interim EPS

**1) Design Goals for the EPS**

- a) Prevent backsliding and commitments that will make future GHG reductions more difficult
- b) Minimize costs to ratepayers and minimize the risk of long-term commitments that will raise the cost of future compliance costs
- c) Reliability:
  - i) short-term: do not force shutdown of essential facilities
  - ii) long-term: consider risks of relying on high emitting resources
- d) Administrative simplicity, regulatory certainty

**2) Timeframe**

- a) Coordinate with procurement proceeding, but adopt now
- b) Implement performance standard as interim measure for an unspecified period of time. CPUC will re-evaluate the program, including consideration of ending the program, when a GHG cap and trade system or other relevant policy (CPUC, state, regional, or other) is functioning.

[9] This does not discourage renewable power or the RECs market. The desirable emissions characteristics of the renewable generation do not disappear. Consistent with the purpose of tradable RECs, the power source that is "covered" by the RECs should be treated as renewable for the purpose of EPS calculations.

3) **To Which LSEs does the EPS apply?**
   a) Apply to all jurisdictional LSEs (including ESPs and CCAs)
   b) Create ESP process to address ESP procurement related to this program
   c) Don't delay pending legislation regarding publicly-owned utilities
   d) Develop a filing/approval process for multi-jurisdictional utilities (MJUs), including a protocol for allocating emissions among resources serving multiple states. Consideration given to MJUs that have prior approvals from other jurisdictions for integrated resource plans (IRP) that include adequate provisions for climate change

4) **Program Screens**
   a) The EPS standard will be applied on a "gateway" basis, at the time a LSE's commitment (build or buy) is proposed.
   b) The standard will be applied to the reasonably projected emission rate (lbs of CO2 per MWh) from the supply source over the term of the commitment
   c) "Covered resources" are resources with a reasonably projected average annual capacity factor of 60% or greater.

5) **Covered Power Sources**
   a) Applied to all new utility commitments, including:
      i) utility owned new generation,
      ii) repowered facilities
      iii) new and renewal contracts for power
   b) All new and renewal contracts and commitments in "covered resources" of five years or longer
   c) Applied to baseload and intermediate or "shaping" facilities with reasonably anticipated annual average capacity factor of 60% or greater
   d) Size threshold:
      i) For specified facilities (built or under contract): 25 MW or greater commitment (e.g. contract size) delivered to the grid;
      ii) For unspecified resource/facilities under contract: 25 MW or greater delivered to the grid under contract commitment.
      iii) For either specified or unspecified commitments: a series of related contracts with the same supplier, likely resource, or known facility, or a series of related or similar contracts with separate sources must be considered as a single commitment in size, capacity factor, and duration.[10] Multiple contracts with the same supplier, likely resource, or known facility are considered to be a single commitment, and must be reviewed as such. Such multiple contract activities must be disclosed by the utilities to the CPUC in order to eliminate "slicing and dicing" of large contracts intended to avoid or manipulate the gateway screening process. Utilities that do not disclose such activities will be

[10] Similar and related commitments should be considered cumulatively with respect to size, capacity factor, and duration. For example, two contracts with a baseload facility, each for 40% of the hours of the year, must be seen as the equivalent of a single commitment with an expected capacity factor of 80%. A contract for a four-year term, linked to a contract for the following 4 years, must be seen as a single commitment for eight years.

considered in violation of the performance and subject to penalty and enforcement.

We recognize that some professional judgment is required to determine when certain contractual commitments are "related" or "similar" so as to trigger review as a single commitment. However this is a common enough problem in environmental regulation and utility prior review programs, and we expect a professional rule of reasonableness to govern its application here. LSEs that are in doubt as to the application of the Rule to new long-term commitments can disclose their contracting patterns to the Commission and seek a jurisdictional determination under the Rule.

e) Application to Qualifying Facilities (QFs) to be determined based upon CPUC review of legal briefs and in accordance with PURPA.
f) Facilities used for self-generation are covered if they are reasonably expected to supply power to the grid above the threshold levels (size, duration, and capacity factor) set in the Rule for other facilities. Credit against emission rates for co-generation thermal loads will be permitted on a case-by-case basis upon a showing of the percentage of facility's useful thermal load.
g) Renewables compliant with the RPS are exempt, unless combined with firming resources. In the case of contracts with firming resources, see below.
h) Reliability exemptions may be permitted, and will be considered on a case-by-case basis

**6) What is the Standard and How Determined?**

a) Emissions standards based upon CCGT performance at ISO levels.
    i) One standard for all covered facilities: equal to a high-performing new CCGT as discussed in the data request. The standard limit is 1000 lbs CO2/MWh.
b) Potential R&D exemption on a case-by-case basis for higher emitting facilities. One example might be an advanced coal facility that has an equal or better emission rate than the estimated IGCC average heat rate and emissions[11], and that has or will have in a reasonable period of time the capacity and existing plan to capture and store carbon dioxide as described in the GHG Performance Standard Policy Statement.

**7) Application of the standard to units and contracts**

a) Single unit specific contracts: contracted unit must qualify
b) Multi-unit contracts: each covered unit must qualify
c) Baseload renewable product with a firming fossil unit(s) that qualifies as a "covered resource": baseload blend average of all covered facilities (renewable and fossil). If firming unit is unspecified impute appropriate emissions factor.
d) Null renewable power treated same as unspecified power. REC-covered power treated as renewable.
e) Unspecified resource contracts: apply CEC "Net System Power" average. This is the statewide system average of the leftover energy in the system that is not claimed- includes in and out of state power, and anything that is not claimed by a

[11] In the response to Data Request Q3, parties indicated an average heat rate of 8630 btu/kWh and emissions rate of 1770 lb CO2/MWh for IGCC facilities.

CA utility, and is the most representative option reflecting CA LSE procurement activities. All LSEs would use the same average emissions factor, regardless of location in the state.

f) For either specified or unspecified commitments: as discussed above in 5)d.iii., a series of related contracts with the same supplier, likely resource, or known facility, or a series of related or similar contracts with separate sources must be considered as a single commitment in size, capacity factor, and duration. Multiple contracts with the same supplier, likely resource, or known facility are considered to be one bulk contract, and must be reviewed as such. Such multiple contract activities must be disclosed by the utilities to the CPUC in order to eliminate "slicing and dicing" of large contracts intended to avoid or manipulate the gateway screening process. Utilities that do not disclose such activities will be considered in violation of the performance and subject to penalty and enforcement.

g) A series of related or similar contracts, regardless of size, that appear to "slice and dice" procurement commitments are not permitted to avoid the standards of the EPS. Related contracts must be considered together as a bulk contract. Multiple contracts with the same supplier, likely resource, or known facility, are considered to be one bulk contract, and must be reviewed as such. Such multiple contract activities must be disclosed by the utilities to the CPUC in order to eliminate "slicing and dicing" of large contracts intended to avoid or manipulate the gateway screening process. Utilities that do not disclose such activities will be considered in violation of the performance and subject to penalty and enforcement.

**8) Monitoring and Enforcement**

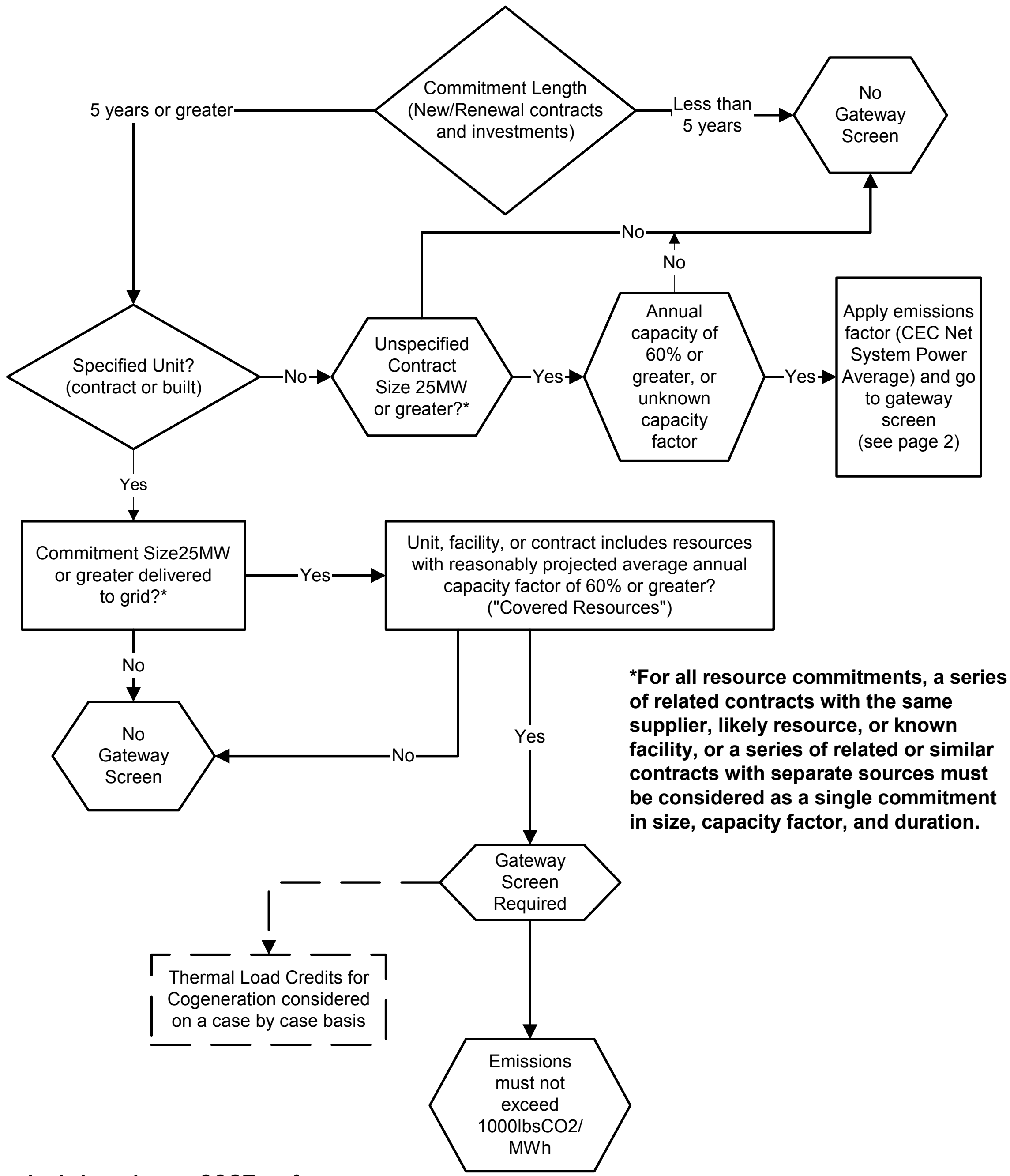
a) CPUC gateway review with documentation and approval required prior to finalizing contract or commitment to construct

**9) Offsets, Safety Valves, and other flexibility devices**

a) No offsets or market price safety valves

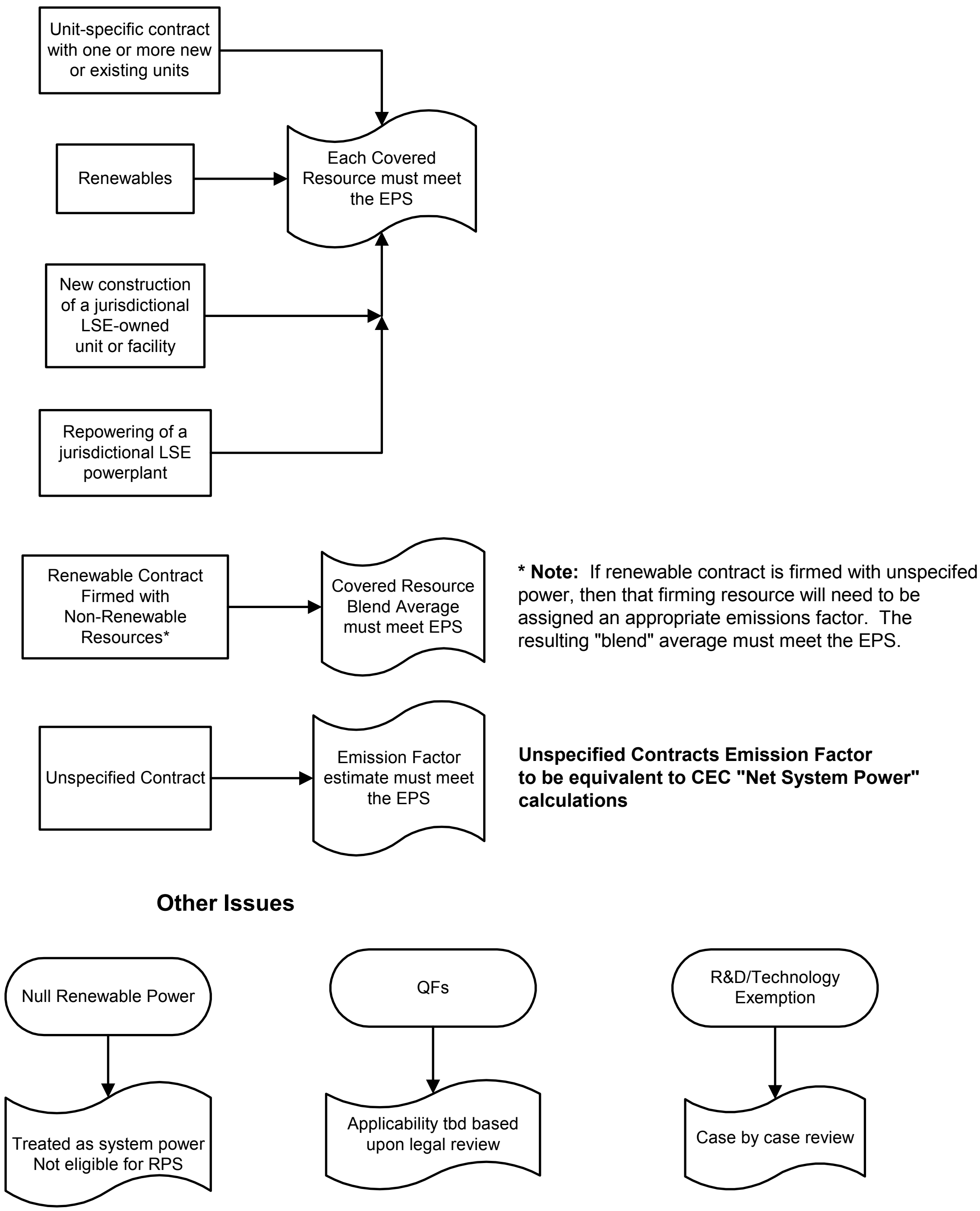
b) Case-by-case exemption for reliability only considered upon application and CPUC review.

# Revised EPS Screen – Covered Commitments




**Emissions standards based upon CCGT performance for facilities built in the last 25 years: 1000lbsCO2/MWh**

# Revised Contract and Unit Specific Requirements to Meet EPS



### D. Request for Participant Comments on this Workshop Report

As indicated in the June 1, 2006 Ruling setting the Phase 1 schedule, opening comments on this Workshop Report are due September 1, 2006 with reply comments due September 12, 2006. Please discuss your views on the updated staff proposal, and support your arguments with specific examples where possible. To the extent possible, include your evaluation of costs and benefits associated with the proposed program and with any modifications that you may propose. Please note that it is not necessary to repeat comments or previous arguments submitted in this phase of the proceeding.

Appendix A

**EPS Pre-Workshop Comments**

**Parties Commenting**
PG&E
SDG&E
SCE
Sempra
Cogen Association and Energy Producers and Users Coalition (CAC/EPUC)
Independent Energy Producers Association (IEPA)
Natural Resources Defense Council (NRDC)
Division of Ratepayer Advocates (DRA)
Int'l Emissions Trading Association (IETA)
Center for Energy and Economic Development (CEED)
Alliance for Retail Energy Markets (AREM)
Center for Resource Solutions (CRS)
CA Attorney General's Office (AG)
Green Power Institute (GPI)
LS Power Generation
Constellation Energy
Calpine

**SUMMARY OF COMMENTS**

**Workshop Question #1:**
Should the Commission adopt an interim EPS to guide ongoing electric procurement decisions while it takes the necessary steps to fully implement D.06-02-032? Why or why not?

**PG&E:** Adopt EPS only if: 1) interim and subject to a guaranteed end 2) applicable to all LSEs, and 3) GHG programs identified in Exec. Order S-3-05 and CAT report likely to be implemented simultaneously (i.e. mandatory GHG reporting, statewide energy efficiency, multi-sector comp. C/T program). EPS not a substitute for or supplement to a GHG cap.

*Costs / benefits:* Will vary greatly depending on design. Significant costs to ratepayers unlikely if EPS applied only to baseload and incremental generation; significant costs likely if applied to ongoing operations and / or shaping and peaking services since CCGT does not provide all the reliability benefits / operating capabilities as non-CCGT technology. If applied to only new commitments, EPS integrates fine with other LSE responsibilities, but RA and LRA contracts should be exempt. Lack of an EPS should not encourage LSEs to "lock-in" higher emissions resources, but applying EPS to only some LSEs could incent non-covered LSEs to do so.

**SDG&E:** No EPS necessary for IOUs; backsliding unlikely since PUC approves all long-term procurement. Incentives already exist (adder, loading order) to promote low-emission generation. EPS more relevant for non-IOU LSEs.

*Costs / benefits:* Will vary greatly depending on design. Significant costs to ratepayers unlikely if EPS defined in the following way (SDG&E's proposed definition): EPS should allow LSEs to purchase: large (>25MW), long-term (> 5yrs), baseload, incrementally acquired or contracted generation from either: CCGT, RPS eligible resources, any non-coal resources that LSEs can demonstrate have projected emissions no higher than if power from CCGT, coal plants with emission rates at least 20% less than conventional coal plant. Total % of coal could be limited in the overall portfolio (5% suggested). SDG&E's EPS would also exclude RA and LRA contracts). The more stringent an EPS, the higher the cost may be since more costly resources will be required – especially if EPS required for units that operate fewer hours (e.g. peaking). More stringent EPS could affect ability to provide reliability and / or reasonably priced electricity. No EPS may create incentives for higher emission resources for non-IOUs LSEs, but not for IOUs.

**SCE:** No EPS necessary for IOUs and unclear PUC has legal authority to implement EPS; backsliding unlikely since Commission approves all long-term procurement; sufficient policies already exist ($CO_2$ adder, loading order, RPS, CSI, energy efficiency and demand response) to promote low-emission generation. EPS provides no incremental environmental benefits. Energy dispatch, not procurement, should be focus of EPS if GHG footprint is main concern. Dispatch is primarily required to be determined by least-cost and the CAISO, and is therefore largely outside the scope of SCE's (and the Commission's) control / discretion. Dispatch for which SCE does have discretion often ties to units necessary for reliability (i.e. peakers) and which do not constitute large amount of energy or GHG emissions. SCE has no discretion regarding the taking of QF contracts, regardless of QF GHG emissions.

*Costs / benefits:* Depending on EPS design, it can increase costs significantly, the extent to which is unclear without further design specifications. Unclear as to how an EPS will benefit customers since EPS provides no incremental GHG reductions beyond those provided by other Commission programs. No EPS would not likely result in "lock-in" of higher emissions because the Commission has approval authority over covered entities procurement and can use this power to not approve projects inconsistent with GHG goals. EPS adoption should wait until the Legislature endorses, and includes munis under EPS. Any EPS would have to be incorporated into IOU procurement plans and may hinder IOUs meeting resource adequacy and local area reliability requirements.

**Sempra:** No EPS. Instead of an EPS a wire-charge should be levied allowing LSEs to manage the CA electric sector's compliance strategies.

*Costs:* loss of fuel diversity (reduction in coal), reduced supply security, higher fuel costs, increased electricity costs.

**CAC/EPUC:** No EPS necessary for IOUs and unclear PUC has legal authority to implement EPS; backsliding unlikely since Commission approves all long-term procurement; sufficient policies already exist ($CO_2$ adder, loading order, RPS, CSI, energy efficiency and demand response) to promote low-emission generation. EPS ensures no GHG reductions and other resources, such as energy efficiency; provide more GHG reductions than CCGT plants. If EPS implemented, should be a multi-sector and/or national program. The EPS will be at variance with GHG programs elsewhere in the country and world, reducing its value.

*Costs / benefits:* Exposes ratepayers to wide range of risks and costs including supply shortages, price volatility (including volatility of gas prices), price increases, leakage costs, compliance costs (admin / regulation design, developing new resources to replace resources in non-compliance). Uncertainty regarding EPS and GHG regulation in general may discourage building of CCGT, leading to shortages and possibly increased emissions as higher emitting resources stay in use / are dispatched more. Uncertainty caused by GHG regulation can also lead to risks not yet known and deferral of valuable reductions by emitters until policies are certain. A CA only, partial sector approach in particular exposes ratepayers to these risks as well as has greater potential for leakage and contract shuffling. EPS could also limit LSEs ability to meet resource adequacy, reliability, and QF requirements.

**IEPA:** No EPS necessary for IOUs; backsliding unlikely since Commission approves all long-term procurement; sufficient policies already exist ($CO_2$ adder, loading order, RPS, CSI, energy efficiency and demand response) to promote low-emission generation.

*Costs / benefits:* EPS may have unintended consequences such as improperly disadvantaging independent power generation. Moreover, an EPS could delay development of C/T program and result in over consumption of stakeholder resources as the EPS is developed / litigated. EPS could lead to higher cost generation. EPS could result in indirect costs depending on its impacts / interaction with grid reliability, RPS compliance, and fulfillment of other policy initiatives. The incremental cost and extra benefits of the EPS should be compared to the cost / benefits of continuing the $CO_2$ adder. The continuation of a $CO_2$ adder also has potential cost impacts (e.g. IPP's increasing bid prices to adjust for a "surrogate" carbon tax). No EPS will not result in increased "lock-in" of higher emitting resources since the Commission approves all procurement decisions. Understanding how costs change with different EPS will require extensive modeling and analysis. Only one standard should be applied to parties, and so if the Legislature adopts a standard, the Commission should collaborate with the CEC so that only one standard is applicable. The EPS could affect timing of LSEs procurement plans and QF purchases. The Commission should declare now that the lack of a final decision on an EPS will not delay planned procurements. The EPS may have the benefit of dispersing generation geographically which could have positive impacts on grid reliability and transmission congestion.

**CEED:** No, an EPS should not be adopted because it would: 1) be economically costly, 2) significantly limit CA's generation options, 3) increase CA's dependence on unreliable and expensive energy sources (primarily gas, but also nuclear and renewables); and 4) unduly burden low income families with higher energy costs (EPS functioning as regressive tax). An EPS in inconsistent with EAP II's goal of relying on "clean and efficient fossil-fired generation" because it sets too stringent a standard for fossil-fuel generation to achieve given current level of clean technology development.

*Costs/benefits:* Almost half of existing CA power supplies would not meet standard resulting in high compliance costs. In particular, cost of renewables likely to increase as demand increases across the west as states implement RPS. Use of $CO_2$ capture / sequestration technology for coal / biomass will raises costs significantly / prohibitively; experience to date with C/S not sufficient to be a viable option. An EPS would also discriminate against Southern California since it has less clean resources (renewables) available. Reliability problems may develop since renewables are not as reliable as fossil-fuel burning facilities and can not, and are not designed to, sufficiently meet baseload demand. It is unclear of net health effect of an EPS (EPS could reduce certain life-threatening risks, but the increased financial burdens could reduce life-span/ reduce safety).

**AREM:** No, an interim EPS should not be implemented for ESPs. It is unclear whether the Commission has legal authority to regulate the GHG emissions of ESPs. If the Commission plans to set as EPS it should be for IOUs only.

*Costs/benefits:* The costs of an EPS on ESPs will outweigh the benefits. ESPs are unlikely to contribute to backsliding problem in next few years due to: suspension of direct access; small load; and because the long-term generation ESPs do provide primarily meet RA requirements (which should be exempt from an EPS). Developing an interim policy for IOUs and ESPs will be costly and time-consuming. EPS can also lead to reduced reliability (noncompliance of peakers).EPS administrative and compliance costs for ESPs would also be burdensome and unlike IOUs, ESPs are not guaranteed automatic cost recovery. High costs could lead to reduce attractiveness of ESP business and reduced market competition. Any EPS should be designed to dovetail with other LSE responsibilities (e.g. RA requirements).

**LS Power:** No EPS should be implemented because existing policies (such as RPS program, loading order, GHG adder) prevent backsliding.

*Costs/ Benefits:* EPS / revision of the procurement process creates regulatory uncertainty and impedes wholesale market development. EPS could increase resource adequacy costs. With No EPS, the Commission's other policies are sufficient to prevent backsliding. The Commission should resolve with the legislature who has jurisdiction to set EPS.

**Constellation Energy:** No. Commission has no legislative authority to impose EPS on ESPs. Legislation should be in place before standard developed. Mandatory emissions reporting is a necessary precursor to an EPS. EPS / GHG policies should be developed / coordinated at the regional level and dovetail with C/T program. Existing policies prevent backsliding.

*Costs/ Benefits:* EPS results in regulatory / litigations costs and implementation costs; especially if conflicts/overlaps with multiple state, regional, and national plans. Non-IOU LSE unfairly disadvantaged because they have to internalize these costs. EPS may eliminate plants needed for reliability and deter investment; lack of regulatory certainty from an interim EPS hinders technology development. Costs could be minimized through monetization of $CO_2$; however creating a durable $CO_2$ value should be done in C/T system, not an interim EPS.

.
**IETA:** EPS is redundant and unnecessary as the Commission has already stated its commitment to implement a cap.

**NRDC:** Yes, an EPS should be adopted to: help achieve Governor's climate change targets, stimulate innovation and investment in low-carbon technologies, protect Californians from significant financial and reliability risks associated with additional investments in higher emitting generation, and prevent backsliding. The EPS should not be considered only as an interim measure (longer application possible).

*Costs / benefits:* A benefit to the EPS is that by moving away from higher emitting generation, it will reduce ratepayers cost exposure to $CO_2$ (assuming a $ value is assigned to $CO_2$). EPS supports the Commission's loading order component of "clean, fossil fuel, central-station generation." It will be beneficial if proposed state GHG legislation (AB32 and SB1368) becomes law because then EPS will apply to all sources. The Commission will need to coordinate EPS with the legislature to make sure that the EPS is consistent with the laws. The EPS should also be incorporated into IOU procurement plans. Regardless, the GHG adder should still be incorporated into procurement plans since the EPS will not eliminate all GHG producing resources.

**DRA:** Yes, an EPS should be adopted to help meet the CAT GHG emissions reduction goals.

*Costs / benefits:* Delays in EPS implementation may encourage LSEs to "lock-in" higher emitting resources and backslide. Enactment of State legislation (AB1368 and AB32) could require modification of an EPS, however the Commission should not wait for certainty regarding state legislation to proceed ahead with an EPS.

**CA Attorney General (AG):** Strongly supports implementation of an EPS because California has a substantial stake in taking every possible action at the earliest juncture to mitigate the potentially devastating impacts- economic as well as environmental- of climate change.

**GPI:** Yes, EPS needed to prevent backsliding.

**Calpine:** Yes, EPS can prevent backsliding. The GHG adder not sufficient deterrent because it is used by IOUs to disadvantage non-IOU resources in the procurement process. The GHG adder should be eliminated with adoption of EPS. The Commission should coordinate with other agencies/legislation in order to not create extra work or create regulatory uncertainty that deters investment. EPS development should not slow down the procurement process.
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**Workshop Question #2**

If an interim EPS is adopted, to which LSEs should it apply? Why or why not?

**PG&E:** Apply EPS to all LSEs in order to prevent "backsliding" by non-covered entities.

**SDG&E:** Apply EPS to all LSEs in order to prevent "backsliding" by non-covered entities. A CPUC EPS only, without a legislative cap would disadvantage IOUs and Non-IOU LSEs subject to CPUC jurisdiction.

**SCE:** Apply EPS to all LSEs, including munis (wide application prevents "backsliding" by non-covered entities). Non equal application creates inequity between customers and may result in customers wanting to switch to ESPs and CCAs if they are not covered by the EPS.

**IEPA:** EPS should apply equally to all LSEs within the Commission's jurisdiction. IEP does not think this will significantly impact competitive markets.

**NRDC:** The EPS should have the broadest application possible.

**DRA:** EPS should theoretically apply to all LSEs. Consideration should be given to how GHG reductions for ESPs (who have primarily short-term contracts) would be measured.

**GPI:** IOUs only at first. Extend to LSEs later as they are not as critical and their inclusion may cause delays.

**LS Power:** Apply to IOUs only. ESPs and CCAs should have discretion in how they meet RPS and RAR, not dictated compliance.

**Workshop Question #3**

3. Over what time frame should the interim EPS be implemented?

**PG&E:** Set EPS concurrently with long-term resource plan adoption (R.06-02-013) and explicitly limited in duration.

**SDG&E:** SDG&E's EPS could be implemented immediately and would influence only utility RFOs for baseload power. SDG&E's EPS is a complement to a cap and therefore could be kept indefinitely, or at a minimum, through Phase II.

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**SCE:** The EPS should be specified for a maximum time period (e.g. 3 to 5 years). The implementation timeframe should allow enough time for clear definition of EPS, development of implementation, clear understanding by parties. Limit EPS to scheduled time of design of load based cap. If implemented, an EPS should be identified as requirement in Commission 2006 Procurement Proceeding decision.

**Sempra:** Should be short-lived.

**CAC/EPUC:** EPS should be sunset no later than January 1, 2010 or when one of the following occurs: regional program, federal GHG regulation, or state GHG legislation that conflicts with EPS. Procedural schedule of 6 months for EPS adoption is short considering all the necessary analysis to be done. The process of developing mitigation programs (RGGI, RECLAIM, etc.) is complex and time consuming. More attention / time needs to be allotted for the development of EPS.

**IEPA:** An EPS could be implemented prior to scheduled procurements in 2007. The Commission should clarify effect EPS would have on and 2006 and 2007 RPS or all-source solicitations. The EPS should be rescinded once a cap is in place.

**DRA:** EPS should be established by the end of 2006 (if evidentiary hearings are not necessary). At a minimum, EPS should remain in place until 1) completion of statewide inventory of GHG emissions from stationary sources and 2) methodology established for estimating emissions from imported power.

**CEED:** An EPS should not be implemented until all details of a GHG cap are determined, including full analysis of costs / benefits.

**AREM:** EPS should end when load-based cap is implemented.

**GPI:** As soon as possible. Should remain in effect until a long-term load based cap is adopted.

**LS Power:** January 2008 at the earliest.

**Calpine:** Could be implemented by early 2007. Should remain in place until permanent measures (load-based cap) in place.

**NRDC:** The EPS can be an ongoing policy to guide addition of fossil-fuel generation and pace technology innovation. Therefore it should not be solely considered as an interim measure and should not have a specific sunset or end. The EPS could be reviewed once cap is in place. If possible EPS implementation should coordinate with SB1368. If SB1368 does not move forward this year, the EPS should be implemented immediately.

**Workshop Question #4**

4. To which power sources should an EPS apply?

**PG&E:** Apply EPS to all, new, long-term (> 5 years), baseload generating plant commitments (LSE owned and contract incl. QF and DG). EPS should not be applied to shaping, peaking, and "reliability plant" resources due to detrimental performance trade-offs that would occur from a strict CCGT standard for these sources.

**SDG&E:** EPS should allow LSEs to purchase: large (>25MW), long-term (> 5yrs), baseload, incrementally acquired or contracted generation from either: CCGT, RPS eligible resources, any non-coal resources that LSEs can demonstrate have projected emissions no higher than if power from CCGT , coal plants with emission rates at least

20% less than conventional coal plant. Total % of coal could be limited in the overall portfolio (5% suggested).SDG&E's EPS would also exclude RA and LRA contracts). The EPS would include any QFs or DG greater than 25MW.

**SCE:** Apply only to: new baseload units and repowering of existing uses for baseload (incl. QFs and DG and including all LSE owned and contracted generation). Since SCE does not believe an EPS should be implemented it provides no comments on what type of subset of generation (incl. commitment length) an EPS should apply.

**CAC/EPUC:** Apply only to: new LSE owned and non-LSE owned baseload (C.F. =>60%), long-term (> 5 years) units. Limit EPS to resources selling more than 200,000 MWh annually (equal ~ 25MW plant at 88% C.F.). CHP should be exempt from EPS. EPS should provide reliability exemptions, esp. if EPS not limited to new generation. Exemptions also for RD&D projects. "Not Unit-specific" purchases should be limited to less than 5 years so that they are not subject to EPS.

**IEPA:** Apply only to: new baseload (C.F. > 60%), contractual commitments, > than 5 years in length LSE and non-LSE owned. If applied to a contract with a portfolio of units, the EPS should be applied to a weighted average of the portfolio. The EPS should apply to QFs. Regarding DG, the Commission must decide if generation built specifically for CA public policy purposes should be exempt.

**NRDC:** Apply to all new and renewed financial commitments for baseload generation, > 5 years. This application simplifies implementation. A minimum size threshold of 5MW should be considered.

**AREM:** Application should be as narrow as possible. EPS should be applied to: new, large, baseload LSE-owned fossil-fuel generation and new long-term contracts.

**GPI:** Standard should be applied to generally to incremental purchases but some exceptions should be made based upon timeframe of purchase commitment, size, and other factors.

**LS Power:** EPS should apply to long-term, new resources/contracts, incl. QF and DG. Should NOT apply to units used for reliability (RA, RMR, LRAR, RCST contracts) and peakers.

**Constellation Energy: >** 5 years and include LSE-owned generation and contracts, but reserves final comment until workshops. Should not impact existing QFs.

**Calpine:** All new, LSE-owned and contracted long-term (> 5 years), baseload power (incl. LD contracts).

**<u>Workshop Question #5</u>**

5. What is the standard, and how is it determined?

**PG&E:** EPS should be lbs Carbon-eq /kWh, and NOT a technology standard. Base on an average heat rate of existing baseload CCGT facilities; use CCAR protocols to set baseline. Offer an exemption process to the standard to allow for new technologies that provide a different, but equally important mix of reliability, cost, and environmental benefits. EPS for peaking should be based on average heat rate of CT technology, not CCGT.

**SDG&E:** CCGT not the correct standard**.** Problems with a CCGT standard: difficult to determine $CO_2$ emissions / MWh, potential higher procurement costs, potential of standard to prohibit support of clean coal technologies. PUC should consider the SDG&E EPS definition offered in response to Q4. The EPS could also limit the total amount of coal allowed in the LSE portfolio if total coal use is a concern with SDG&E's proposed EPS. If CCGT used, all types of CCGT should qualify and so moot whether standard should refer to turbine or total facility. If CCGT based, standard should be based on highest known $CO_2$ emissions rate for an existing CCGT in the West. Any other definition of CCGT, in particular one that requires consideration of operational characteristics and emissions measurements for baseload and peaking, will be too complex and subject to litigation.

**SCE:** CCGT is a reasonable and simple proxy for estimating GHG emissions. An alternative is not proposed. EPS should be based on an average of historical emissions (over at least an operating year) from operating CCGTs and should consider emissions over different operating conditions (including seasonal and operational effects). Emissions should be measured for the whole facility, not the gas turbine alone. An EPS for any subset of generation (incl. peaking vs. baseload) would also need to consider operation under different possible conditions/operating parameters.

**IEPA:** CCGT is appropriate starting point for EPS, however deriving a "fleet average" of a CCGT is complicated. The EPS should apply to the facility, not the turbines and should be based on the weighted average performance of a broad sample of CCGT units. Theoretically all emissions (incl. start-ups) should be counted however this could be an unfair burden for generators since the CAISO largely determines generator start-ups.

**GPI:** Yes, use the standard based upon the CCGT. That standard should be applied against the expected GHG performance of any proposed contract.

**LS Power:** EPS should consider need to maintain some capacity for reliability purposes. A CCGT based EPS should be based on an expected emissions profile from a generic combustion resource, reflecting average fleet age. EPS should be based on stabilized operation point (not start-up).

**Constellation Energy:** CCGT standard based on 'average emissions factor" not practical since it puts at risk ½ of supply resources.

**CAC/EPUC:** EPS should be 0.93 lbs/kWh instead of technology based. EPS should allow coal w/ carbon sequestration to be developed.

**NRDC:** EPS should be emissions level of a CCGT expressed in $CO_2$ / MWh. EPS should be enforced at time of approval of contracts and investments and be based on contract terms, design specifications, and operation expectations.

**Calpine:** A CCGT, facility based standard expressed in an emission per unit output basis (e.g. lbs / MWh). EPS should be based on a benchmark unit operating in the CA fleet. A clear definition of facility would be necessary (should not include ancillary equipment).

**IETA:** CCGT should not be the proxy. Market mechanisms should play a role.

**CRS:** Specific to 5(f): What other factors or options should be considered in defining a CCGT (or other) standard:

> Wants to ensure that Renewable Energy Credits (RECs) are not double counted by the RPS program and a GHG cap program, or any other way. CRS suggests that if RECs are sold separately, and the electricity is sold as “null” power, then the power should be assigned a GHG emissions value. The value could be based upon average emission or some other default factor. The CPUC should stipulate that for renewable generation to retain zero emissions value for the purposes of the EPS, associated RECs should be retired in WREGIS.

**Sempra:** An EPS could be used as the basis for incremental charges for new resources AS PART of a wires-charge program. However, it should be quickly transitioned to a centralized mechanism.

**Workshop Question #6**

6. Applying the standard to covered resources

**PG&E:** EPS should be applied to facilities as a whole, not turbines specifically, and should not be applied to the whole portfolio (otherwise it becomes a load-based cap). Include renewables as part of more comprehensive GHG program, but not the EPS. Non-specific and unregistered sources: assign emissions value equal to average emissions profile of region based on average contract heat rate of comparable natural gas baseload facilities in that region. CHP facilities: cover on a case-by-case basis.

**SDG&E:** EPS should not be based on measured emissions because that will requires resolution of Phase 2 issues (emission measurement methodology) and is too significant an undertaking for Phase I. Instead, EPS should be based on projected emissions and applied at the time of contract. “Non-identified” resources should be assigned a gas plant emissions rate or a rate based on the implied heat rate. With SDG&E’s EPS, LSEs would establish at time of contract approval that “non-identified” resource meets EPS. CHP should be considered on a case-by-case basis and include reductions from thermal load and QFs and DG should be covered also. Since projected capacity factors will be known, life-cycle based emissions possible, but neither life-cycle nor immediate facility emission analysis necessary with SDG&E's EPS. EPS should be applied to facilities only. If applied to entire portfolio it becomes a form of load-based cap and then conventional coal would be allowed.

**SCE:** EPS application faces possibly insurmountable accounting / tracking issues. Tracking issues result because: there is not a correlation between power purchases and actual operation of these units, contract shuffling is possible, there are numerous transactions and market participants. It is reasonable to consider CHP thermal emissions, but SCE does not have a specific proposal. It is unlikely an EPS applied to an average of LSE's new resources would encourage investment in coal generation because of other Commission programs/rules.

**Sempra:** Should be applied on a contract / portfolio basis (if contract made of many units) and not a facility basis. Resource blending should be allowed.

**CAC/EPUC:** EPS should be applied as a one-time "gatekeeper" rather than an operating standard. If CHP not exempt then the rate of emissions should be based on total electrical and thermal output.

**IEPA:** If emissions from specific units not know the Commission should impute a level of GHG emissions for the contract based on the highest emitting, marginal baseload generation facility located outside of CA. This approach of a "worst-case" default should result in contracts being more transparent and disclosing emissions. CHP should be considered on a case-by-case basis. Only net fuel use should be counted for CHP. FERC filings could be used to compute "net fuel." Determining emissions on a life-cycle basis for CCGT will be very difficult. The EPS should be applied to every contract, not a portfolio.

**NRDC:** EPS should be applied on a life-cycle basis, to the whole facility, on an individual contract base and not to entire portfolio (otherwise reduces EPS's technology innovation thrust). System power purchases should be linked to specific sources, and each generation source within a contract should meet the EPS. If not possible, a default emissions rate of a conventional coal plant should be assigned to non-specified resources. CHP should be subject to EPS (on a case-by-case basis), but get credit for thermal energy. Contract shuffling is a short-term concern and should not affect the EPS.

**DRA:** Compliance should be determined by comparing emissions from covered resources to EPS.

**CEED:** Without more detail on EPS it is impossible to say how it should be applied. Depending on its definition (which for CCGT can vary based on plant location, turbine technology, etc.) varying amounts of CA plants could be or not be in compliance. For CHP, some consideration of thermal output necessary.

**GPI:** Apply consistently to new utility procurements. Should not be applied on a system basis- No fleet averaging.

**LS Power:** Cannot apply to "not specified" system imports. For specified units, apply on unit level, not portfolio. Interim EPS will skew procurement decisions by deferring investment until more regulatory certainty. An annually updated EPS, or one applied to existing sources, likely lead to more regulatory risks being assigned to asset owner.

**Constellation Energy:** EPS problematic because applying standard to "not-specified" sources difficult and unclear how this would work.

**Workshop Question #7**

7. Monitoring and enforcement

**PG&E:** Compliance with EPS should be demonstrated at time of approval of procurement. Compliance demonstrated through: submission / review of design documents (supplier should not be required to register with CCAR). QF and DG compliance should require engineer-verified documentation. CCAR should use its systems to monitor compliance. Monitoring should be limited to ensuring the facility subject to standard is not modified in any way that differs materially from original compliance.

**SDG&E:** The EPS should be based on design standards, not actual operations. Therefore, appropriate role of CCAR should be considered in Phase II when emissions monitoring is scheduled to be discussed. If actual emissions are monitored, extensive review and potential litigation of operation data would occur. Monitoring / compliance with SDG&E's EPS (for generation not automatically complying based on its design characteristics) would require review of permit and contract data or standard emissions factors could be developed by the Commission or CEC.

**SCE:** CCAR should not perform a role in monitoring and enforcement because it is not an official state agency. This role would conflict with the legislative purpose of CCAR. Compliance could be measured through EPA's Continuous Emission Monitoring System (CEMS) reports. Data on fuel use and heat rates would be required which is available in the EPA's Electronic Data Reports (EDR). QFs and DG would require monitoring of total emissions and total output, requiring additional metering.

**CAC/EPUC:** Early reductions registered with CCAR should be recognized within any GHG program. Due to large number and types of contracts and parties (including CAISO), tracking emissions may be difficult, if not impossible. A requirement of ongoing compliance detrimental because: risk that new unit may not continue to meet standard in the future, may affect contract terms (contracts will be changed to be less than EPS contract length requirement), and would require a comprehensive monitoring program. CAC/EPUC supports mandatory reporting of emissions by generators directly to utilities. The utilities can aggregate this data for CCAR (maintaining confidential individual generator data).

**IEPA:** The CCAR should play a role in designing protocol for reporting, serving as a single repository for collected information, and verifying reported information. Compliance should occur at the time of contract commitment and should not be imposed on real-time operations. Compliance should be based on generation characteristics and design operating specs. For existing facilities and QFs, data available from agencies (e.g., CCAR, FERC, EIA, CEC). Financial penalties should be levied for lack of compliance.

**NRDC:** No ongoing monitoring will be necessary since EPS enacted at time of contract / investment approval. Since compliance is determined at time of approval, no financial penalties are necessary.

**DRA:** CCAR should be used as a centralized repository of compliance information.

**IETA:** Should be coordinated and compatible with other cap programs (RGGI, EU, etc). Should have independent verification and monitoring. Comments do not specifically speak to the role of the Registry.

**AREM:** It is premature to discuss penalties and enforcement.

**GPI:** CCAR can be a source of information on emissions, but should not be asked to play any role in the enforcement of a standard.

**LS Power:** Require compliance at time contract/resource is approved. Documentation same as RFO documentation. Offsets should be required if compliance not reached.

**Constellation Energy:** Emissions reporting should be mandatory. Penalties should not be imposed in there is no ability to meet EPS.

**Calpine:** CCAR should be used as a repository for mandatory reporting. Reporting should be an EPS approval requirement and methodology should be based on CCAR protocols.

**Workshop Question #8**

8. Offsets, Safety Valves, and other flexibility devices

**PG&E:** No offsets would be needed for an interim EPS. Offsets would be needed for C/T.

**SDG&E:** No offsets would be needed for the SDG&E EPS. Offsets may be needed for other definitions of an EPS, especially if EPS was defined as average of $CO_2$ emissions of existing CCGT plants or if EPS was applied to peaking units. A safety valve helps maintain compliance flexibility. The issue / concern regarding the extension of existing, higher emitting resources should be addressed in Phase 2, not Phase 1 since it is related to load-based cap.

**SCE:** Geographically unrestricted offsets are critical component of EPS because: they minimize cost and export CA technology and best practices to others. Offsets should be included to coincide with EPS implementation. Existing higher-emitting resources required for system reliability should not be retired without a sustainable market to develop / add new resources. Forcing premature retirement of existing generation is expensive and harmful to GHG goals because it could raise electricity costs as well as lock in reliance on natural gas generation. RD&D is the critical element to address climate change, not regulation, especially since the Commission jurisdiction is too small. A price cap / safety valve at a cost no higher than the GHG adder should be included in EPS.

**Sempra:** Offsets should be allowed.

**CAC/EPUC:** Discussion of offsets should be deferred until if and when an EPS is set. Other resources such as CHP and energy efficiency can be used instead of an EPS to reduce GHGs. If EPS is set, offsets should be allowed. Provisions are also necessary to reduce risk / exposure non-utility generators have to GHG regulation. Standardized or default contract provisions are required to equalize the position of utility and non-utility generators in negotiations during the development of GHG policies (contracts should be required to expressly link benefits of carbon attributes and risks of carbon regulation).

**IEPA:** Offsets should be allowed if verifiable. However, the time and resources required for developing an offset program not justified for an interim program unless offset program will be used as part of a C/T program. To reduce extended use of higher emitting resources, the Commission can adopt market elements to bring on new generation; however the relatively clean nature of CA's fleet suggests that a concern over extension of higher emitting resources may not be well founded.

**IETA:** Strongly supports offsets as part of all programs/phases being contemplated. Does not support a "safety valve".

**AREM:** EPS should be as flexible as possible and include: banking, offsets, and safety valves.

**LS Power:** Offsets (with one-time, retiring credits) should be allowed. Asset owners should receive credit if they retire and replace a higher emitting unit (used for RA) with a newer, less-emitting unit.

**Constellation Energy:** Offsets should be allowed and all alternatives/flexible compliance mechanisms considered.

**NRDC:** NRDC strongly urges that no offsets be allowed (they reduce technology focus, dilute goals, and no appropriate verification system exists).

**Calpine:** No offsets for interim EPS; address issue for permanent plants in Phase 2. Reliability exceptions should be subject to rigorous test and be used limitedly.

**GPI:** Flexible compliance should be discussed in Phase 2 and is not relevant to an EPS.

**Workshop Question #9**
9. Other Issues

**PG&E:** Coordinate this proceeding and utilities' 2006 procurement plans.

**SDG&E:** SDG&E's EPS complements planning process and so additional coordination not needed. Alternative EPS structure might require additional coordination efforts.

**SCE:** EPS should be coordinated with other procurement related filings. EPS should preserve flexibility of planning efforts that currently evaluate resources on host of factors (timing, cost, reliability, emissions, etc.) The timing and development of low emissions resources needs to be analyzed to incorporate EPS into planning.

**CAC/EPUC:** EPS could affect IOUs long-term procurement plans and create tension with goal of least-cost procurement. CAC/EPUC details the GHG reductions expected as part of other CAT programs as justification for why an EPS is not needed as well as offers Oregon as an example of a state engaging in other, less aggressive GHG reduction measures. CAC/EPUC also provides details on how emission-related markets interact with fuel and electricity prices that would be relevant potentially for the cap discussion in phase 2. CAC/EPUC also details tasks necessary for creating a long-term climate change policy (incl. modeling and policy design) that are not summarized here.

**Sempra:** The Commission needs to clearly specify GHG emissions reduction goals for the electricity sector and allow industry to implement its own program to meet the Commission's goals.

**IEPA:** IEP offers comments on how an effective cap and trade program (e.g. multi-sector, leak proof, etc.) should be designed which are not summarized here. IEP offers comments on how the use of the $CO_2$ adder policy should be more transparent.

**CA Attorney General (AG):** Cites a litany of scientific research indicating that climate change is real.

Appendix B
(Note: Names and contact info subject to typos due to the handwritten nature of the sign-in sheets).

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Appendix C

**May 31, 2006**

**To: All Parties in R.06-04-090**
**From: Division of Strategic Planning**

**RE: Direction for Workshops on the Interim Greenhouse Gas Emissions Performance Standard for Electric Resource Procurement**

As discussed at the May 10, 2006 prehearing conference (PHC) in this rulemaking, Phase 1 will focus on the policy, design and implementation issues associated with an interim greenhouse gas (GHG) emissions performance standard (EPS) intended to serve as a near-term bridge to the load-based GHG cap adopted by the Commission in Decision 06-02-032. [12] A set of workshops to develop the record and the understanding needed to craft an appropriate EPS will be held on June 21-23, 2006.

This memorandum provides guidance to the parties on the structure of the workshops and the issues to be addressed at them. Pre-workshop comments are invited on both the structure of the workshops and the substantive issues raised. Pre-workshop comments must be filed and served by the close of business on June 12, 2006. They are to be served electronically to the service list pursuant to the Electronic Service Protocols attached to the Order Instituting Rulemaking (OIR) and consistent with Rules 2.3 and 2.3.1. As directed in those protocols, hard copies are also to be served on Administrative Law Judge (ALJ) Gottstein and the Assigned Commissioner.

## I. Overview

The starting point for analysis at the workshops will be the EPS set out by the Commission in its 2005 GHG Policy Statement. However, the language of the OIR does not limit our review to that particular design; thus the workshops will examine other leading options and modifications. Three days of workshops are scheduled. We anticipate that Day 1 will focus on overall policy questions, while Days 2 and 3 will address design options, implementation details and data needs.

## II. Workshop Day 1

The first day of the workshops will focus on the basic policy questions underlying the proposed interim EPS. We will begin with a short review of the basic relevant data: As a general matter, what new procurement needs are load-serving entities (LSEs) anticipating filling in the next three to five years, and what fraction of those needs would be affected by an EPS that requires new procured resources to have a GHG profile no higher than that of a combined cycle gas turbine (CCGT).

[12] We use the single acronym "EPS" throughout this memorandum to refer generically to a GHG emissions performance standard.

Each investor-owned utility (IOU) LSE should be prepared to provide such a short overview at the beginning of the first workshop. In answering this question, LSEs should consider a range of possible interim EPS rules, from one covering all new MWhs from all sources, to one covering only the largest, most long-term procurements. The workshops do not require detailed studies or resource plans from LSEs; where plans are uncertain, scenarios can be presented as options. Other respondents with information or projections concerning the possible application of the EPS to other LSEs will also be invited to present those projections.

With this basic information in hand, the workshop will consider four questions:

1. Should the Commission adopt an interim EPS to guide ongoing electric procurement decisions while it takes the necessary steps to fully implement D.06-02-032? Why or why not? Address the following in your response:

a. What are the likely costs and benefits of imposing a performance standard on LSEs and their customers?
b. Would failure to adopt a performance standard create unwise incentives to some LSEs and customers to "lock in" higher emission resources before an anticipated cap-and-trade system is imposed?
c. How sharply do EPS costs and benefits vary with the type of performance standard imposed? With different assumptions about the future cost of carbon compliance?
d. How do the performance standard and cap proposed by the CPUC interact with proposed state legislation in this area? How might potential legislation affect CPUC action in this proceeding?
e. How would an interim EPS interact with the LSEs' other responsibilities under the Commissions procurement orders?
f. If the main purpose of the EPS is to forestall "backsliding" pending adoption of a load-side cap, are there other policies that could have the same effect in a more direct or simpler fashion?

2. If an interim EPS is adopted, to which LSEs should it apply? Why or why not?[13] Address the following in your response:

a. Should the standard apply solely to IOUs, or should it apply to all non-municipal LSEs within the Commission's jurisdiction (including ESPs and CCAs)?
b. Should the CPUC implement an EPS for LSEs within its jurisdiction while leaving the possible inclusion of public power entities to the Legislature? Would this result in major undesirable impacts on competitive markets, power flows, or system reliability and if so, how might those impacts be mitigated?

[13] Discussion on this topic during pre-workshop comments and at the workshop will focus on policy issues, not legal issues. As discussed at the PHC, there will be a separate opportunity for briefs on Commission jurisdiction with respect to the adoption of an interim performance standard to non-IOU LSEs.

3. Over what time frame should the interim EPS be implemented?

   a. As a practical matter, how soon could an EPS be implemented?
   b. Are any significant procurement decisions now pending or soon anticipated that ought to be covered by a new EPS policy?
   c. How long should the interim EPS be kept in place?

## III. Workshop Days 2 and 3

The workshops on June 22 and June 23 will need to proceed under the design assumption that the Commission will elect to adopt an EPS to guide power procurement decisions, at least until an effective load-side cap is fully implemented. Here we will examine how such an interim EPS should be designed and implemented so that it could be put in place quickly to serve this purpose.

Initial summary of EPS options.

The second workshop will begin with a brief overview of the basic options for the EPS. These workshops will address the following topics:

4. To which power sources should an EPS apply?

The EPS under discussion in this proceeding focuses on incremental procurement actions, particularly to avoid "backsliding" in those investments and procurement decisions by jurisdictional LSEs. This focus raises several questions to be addressed in your pre-workshop comments and in the workshop discussion. Please be as specific as possible as to your proposed design, should the Commission elect to adopt an interim EPS:

   a. Should the EPS apply to *all* incremental purchases, contracts and/or units, or to a subset of them? If a subset is appropriate, should it be defined in terms of:
      - Size of unit or contract (e.g., MW capacity or MWh supplied)?
      - Length of contract?
      - Generation type (e.g., baseload versus peaker)?
      - Other definition of subset?
      - Some combination of the above?
   b. The Commission's policy statement suggests applying the EPS only to commitments greater than five years in length; is this the right threshold for "long-term" commitments? Would three years be more appropriate? Does a shorter term just create greater incentives for short-term contracting?

c. Should the standard apply to LSE purchases from Qualifying Facility ("QF') contracts and Distributed Generation ("DG') contracts?
d. Should the standard apply only to LSE contracts and purchases, or to LSE's own new units? Should it apply to repowering existing units?

5. What is the standard, and how is it determined?

In its October 6, 2005 GHG Policy Statement, the Commission anticipated a performance standard for new procurement that would be set at the emissions level of a CCGT. Workshop participants will need to address how such a standard would be defined, and may also propose an alternative standard as long as one could be implemented in the near-term. In considering this issue, please respond to the following specific questions:

a. Is the CCGT standard the right standard to use, or is there an alternative standard that would be more appropriate *and* that could be put in place quickly for an interim EPS?
b. If a CCGT standard is used, will it be based on expected performance of a modern CCGT newly placed in service, or a CCGT at the end of its useful life (since performance degrades over time), or an average of emissions from existing CCGTs?
c. How will this standard be measured--based on the emissions from a gas turbine only or from the entire CCGT facility?
d. If peaking facilities are measured against the standard, would the standard be based on the heat rate of the duct firing of a CCGT or the start up of the CCGT? If the latter, what would be the assumed duration of operation?
e. If the EPS is applied only to baseload units or contracts, will the standard be based on the CCGT facility heat rate or will emissions from start ups be considered?
f. What other factors or options should be considered in defining a CCGT (or other) standard?

6. Applying the standard to covered resources

Once a standard is defined, compliance must be calculated by comparing the emissions from covered resources to it. This requires measuring emissions from covered resources, or assigning attributes to them. Address the following questions in your discussion of these issues:

a. How should purchased power contracts, especially those from systems outside California, be treated? The Commission has in other contexts identified "contract shuffling" as a potential problem in assigning emission characteristics to power purchased by California LSEs. Can purchases from other power systems be treated on a unit-identified basis, or must system attributes be assigned?

b. If generation associated with combined heat and power is included in the program, how is the thermal side of the combined heat and power operation accounted for? In implementing the standard, should the Commission adopt an assumed efficiency for the stand alone thermal application, or will case-by-case review be needed?
c. Will the emissions from covered resources be treated on an immediate facility basis, or on a life-cycle basis, compared with life-cycle emissions from a CCGT?
d. Should the EPS apply to each and every resource added to an LSE's power portfolio, or can the LSE average across new resources? That is, would it be appropriate to allow some "fleet averaging" across an LSE's separate (incremental) units or contracts? In considering this issue, discuss how your position would or would not:
    - Be consistent with the treatment of single power-purchase contract that are backed by multiple units;
    - Skew power contracting decisions.
e. If LSEs *are* permitted to average across their new resources, should renewables that meet RPS requirements be included in the average? What effect would this have on the ability of California LSEs to purchase new coal-generated power?

7. Monitoring and enforcement

a. What role should the CCAR play in collecting information on source emissions and monitoring compliance with the EPS Rule?
b. If a GHG performance standard is adopted, how will compliance be measured if procurement decisions are made before mandatory CCAR registration? Based on heat rate and fuel type?
c. What documentation will be required to demonstrate compliance?
d. If combined heat and power QFs and DG are included, what type of documentation of the use of thermal energy is required?
e. If a jurisdictional LSE does not satisfy the EPS with respect to a covered resource, should financial penalties, other remedies or both, be employed?

8. Offsets, Safety Valves, and other flexibility devices

Some participants have requested that any EPS Rule contain flexibility devices, potentially including offsets. There is also some interest in "safety valves" that would relax the program if its impact on power prices was too great, or it was seen to impose system reliability risks. In considering these and other related issues, provide a response to the following:

a. What are the pros and cons of permitting offsets for an interim program of this nature?

b. If you believe that offsets should be permitted, be specific with regard to the nature of allowable offsets and associated implementation steps (including timeline) to put an offset system in place.
c. Given the EPS focus on new acquisitions, how can the Commission address the potential undesirable incentive for LSEs to extend the operation of existing, higher-emitting resources? Should LSEs be offered the equivalent of credits against replacement power sources[14] if high-emitting resources are retired during the period of the performance standard? Are there other approaches that the Commission might consider to address this issue?
d. Considering the scope of the EPS rule, and the basic information provided by LSEs about its reach, are safety valves of any kind needed? Is a "reliability override" needed, and if so, how should it be defined and administered?

9. Other Issues

- How would in interim EPS adopted in this proceeding be coordinated with the utility planning procedures and requirements emerging from the current procurement docket?

## IV. Workshop Structure

At the three day workshop, we will work through the questions presented in sequence. *All workshop participants are expected to file pre-workshop comments addressing the issues/questions presented above.* As each topic is raised, we will present an overview of the pre-workshop comments on that topic. We will focus on general group discussion to clarify the range of views concerning the pros and cons/options under each of the topic areas, rather than spend time reiterating or further clarifying each individual participant's positions. The discussion will be structured to assist us in identifying the leading options on each point, and where possible, to uncover points of consensus. Areas of disagreement will also be noted. The workshops will identify as much common ground among participants as possible, but we will not defer action on later items in order to find consensus on earlier points. Time permitting, the group will return to discussion of unsettled topics after working through the full list.

In addressing the Day 1 questions, respondents and interested parties should present their best assessment at this time of the costs, benefits and co-benefits (e.g., job-creation, economic impacts) associated with the establishment of an interim GHG emissions performance standard. Throughout Days 2 and 3, the parties should keep in mind the focus of this phase on an interim or "bridge" performance standard that can be

[14] This would be similar to the application of "early reduction credits" in other pollution management regimes.

put in place quickly. As discussed at the PHC, the utilities and interested parties are expected to ensure that their technical and policy experts on these issues attend the Phase 1 workshop, so that there can be a productive dialog on these matters.

Data issues:

The purpose of these workshops is to identify the pros and cons of different approaches to an interim EPS to guide the Commission's eventual decision in Phase 1. As discussed at the PHC, a Commission determination in Phase 1 will benefit from an analysis of basic information on procurement options but will not require extensive data collection or economic modeling. Accordingly, some basic data will be needed to guide discussion and to consider some of the EPS's benefits and costs, but these workshops are not intended to develop extensive studies or power cost models for this purpose. As noted above, each IOU respondent is required to provide a brief overview of its resource procurement needs on Day 1.

For this purpose, as suggested at the PHC, the utilities and interested parties discussed data needs at a May 22, 2006 conference call. Following up that meeting, the Division of Strategic Planning has directed, in consultation with ALJ Gottstein, that the respondent IOUs serve the following information electronically to the service list by close of business on Wednesday, June 7, 2006:

Q 1 What percentage of current contracts is "dirtier" than CCGT? What percentage of currently owned generation is "dirtier" than CCGT?

Q 2 What percentage of contracts is not tied to specific units? How many MWs and MW-hrs do these contracts represent?

Q 3 How many contracts and how many MW-hrs are equal to or less than three years in length? Equal to or less than five years in length?

Q 4 How many MW/MW-hrs are you planning to procure (add, renew, or turn over) in the next three to five years, and what are your anticipated resource additions (and which kinds of resources) at this point in time? What are the cost and reliability impacts, and benefits and co-benefits, of migrating these resources to those as clean as or cleaner than CCGT?

Q 5 What are the cost and reliability impacts, and benefits and co-benefits, of migrating 10% of your current portfolio? Of migrating 20%?

In presenting this information, the IOUs should include all sources and assumptions underlying their responses to this data request. The IOUs are expected to prepare a short presentation of this material on Day 1 of the workshop, with hard copy handouts to the workshop participants. [15] They will need to coordinate with the workshop facilitator (see below) ahead of time with respect to the handouts, time allotted for presentation, etc.

Workshop participants who intend to provide additional information to guide the workshop discussion should submit them with their pre-workshop comments on June 12, 2006, together with all underlying data sources and assumptions.

Workshop leaders:

These workshops will be led by Richard Cowart of the Regulatory Assistance Project (RAP) with assistance from Lainie Motamedi from the Division of Strategic Planning. ALJ Gottstein will also be in attendance. Participants are invited to contact Mr. Cowart directly with workshop questions and suggestions at RAPCowart@aol.com, or 802-223-8199.

Agenda and Presentations:

Suggested modifications to the questions presented above, or to their order of discussion should be filed with parties' pre-workshop comments by June 12. Those who wish to schedule presentations to the group on one or more of the topics above should contact Richard Cowart. He will consider those requests and finalize the agenda in consultation with ALJ Gottstein and the Division of Strategic Planning.

[15] They may also make further refinements to the June 7 submittal for this purpose. If further refinements in the June 7 responses are made, the IOUs should clearly present in their workshop hand-outs the nature of the refinements, along with any updated data or source information.

**Appendix D**

Data Requested at the June 21-23 Workshop

At the workshop, the IOUs (PG&E, SDG&E, SCE) and other workshop participants agreed to prepare the information/analysis on topics related to the threshold policy issue and implementation design considerations for an interim EPS, as follows:

1. The size of the potential IOU procurement needs that would be covered by an interim EPS. The IOUs and the CEC are working on a common format for this information and will be providing the format to staff by July 7. By July 11, both redacted (public) and unredacted versions of this information will be provided to staff. The intent is to provide to the service list as much publicly available data on this topic as possible.

2. Analysis around the definition of "covered resources:" What proportion of GHG emissions from long-term commitments would be excluded/included if the threshold for review is 60% average annual capacity factor vs. 50%, 70% or 80%? The IOUs will be providing this information to staff by July 11th.

3. Graph/Schematic of representative heat rates/emission rates for different types of facilities, for the purpose of considering the level of the "moderate" and "high" EPS thresholds for existing/new facilities under the staff Straw Proposal, or alternative approaches. The IOUs and other workshop participants agreed to coordinate on this document, due July 11 to staff.

4. Size of potential ESP procurement. SCE and AReM are working on this information that will be submitted to staff by July 14.

5. Emission factors for unspecified resources. CEC staff will provide the WECC regional emissions average, sub-region averages and the "net system" average figures to staff by July 11.

6. Potential new sources of power (new projects coming on line) proposed for potential sale to California IOUs. CEC, WRA, Constellation and PacifiCorp agreed to pull together the data available on this issue, and provide it to staff by July 11.

In addition, at the workshop several participants agreed to coordinate the development of the following information to present in their post-workshop comments (jointly, if possible):

a. How one would calculate the net emissions rates from renewables (GPI, PG&E, NRDC and others)

b. The formula for a cogeneration thermal credit calculation, and whether it is consistent with the CARB approach: (EPUC circulating to others before comments are due)

c. Protocol for assigning "covered resources" to California for multi-jurisdictional utilities and other implementation issues unique to multi-jurisdictional LSEs (PacifiCorp, WRA).

Staff intends to serve the information listed under 1-6 above to the service list upon receipt, so that you will have it as soon as possible to consider for your post-workshop comments. If you are interested in participating in the development of this information, please contact the parties listed above as soon as possible. The service list with contact information is accessible at www.cpuc.ca.gov. In addition, you can contact Lainie Motamedi (415 703-1764) or Carla Peterman (415-703-1112) in our Strategic Planning Division for questions or further information about these submittals.

Thank you,

ALJ Meg Gottstein

Responses to the Data Request are posted at
www.cpuc.ca.gov/static/hottopics/1energy/r0404003.htm

**Appendix E**

## DIRECTIONS FOR PHASE 1 POST-WORKSHOP COMMENTS

We are soliciting post-workshop comments in order to further develop the record on the policy and implementation issues associated with the Commission's consideration of an interim GHG emissions performance standard (or "EPS"). The post-workshop comments may also respond to the arguments made by parties in pre-workshop comments. However, the focus of the post-workshop comments should be to further elaborate on specific areas of discussion at the workshop, including the following:

A. Threshold Issue: Should the Commission adopt an interim EPS?

1. If you are in support of an interim EPS, describe the advantages of adopting one. If you recommend that the Commission *not* adopt an interim EPS, present opposing arguments on this issue. ***Please initially respond to this question in the context of the "gateway" EPS described in Appendix A (Staff Straw Proposal). If your response would differ based on an alternative EPS design, please so indicate.***

2. In the context of your answer to #1 above, address whether an EPS serves to address the Commission's goals for procurement differently/better than current procurement policies, such as the current GHG adder. If the GHG adder were significantly increased, would this obviate the need for an EPS, in your view, why or why not? In your response, describe the current purpose and application of a GHG adder relative to an EPS.

B. Implementation/Design:

3. Assuming that the Commission decides to proceed with an interim EPS, what should be the major design principles/objectives for such a standard? Please identify what you consider to be the ***top four prioritie***s for design criteria, and why. The following is an illustrative list developed from the workshop discussion, but others may be presented and discussed.

The EPS should:

--Be designed to prevent major "backsliding" (and if you choose this design objective, please clearly define your use of the term "backsliding");
--Be workable and administratively as simple as possible.
--Address reliability concerns, e.g., be designed to prevent the shutdown of essential facilities;
--Signal development away from high-emitting resources;
--Encourage (as well as not hinder) advanced technology development;
--Minimize costs to ratepayers;

--Minimize the risk of long-term commitments that will raise future compliance costs;

--Other?

4. The first major fork-in-the-road design issue discussed at the workshop was whether the EPS should be a "gateway" threshold versus a standard that applies to the ongoing operation of a facility (built or under contract). The general consensus of workshop participants was that an interim EPS should be a gateway standard that is applied when the load-serving entity (LSE) seeks approval for construction or purchase commitments, based on documentation concerning the expected resource/facility operating characteristics and associated GHG emissions.

Please discuss the relative advantages of this approach, and the potential disadvantages. If you believe that the EPS should in fact be applied in a different manner, please describe your proposed approach and the relative advantages/disadvantages of your proposal. Relate your response to this question to the design priorities you articulate under Question #3 above.

5. Another fork-in-the-road design issue discussed at the workshops was the application of an EPS to new generation resources as well as to renewal or new contracts with existing facilities. The Staff Straw Proposal applies the EPS to new ***commitments*** (construction, new or renewal contracts) for both. (See Appendix A.) Please comment on whether you support the Staff Straw Proposal on this issue, indicating your views on the relative advantages and disadvantages of applying the EPS to both new and existing generation facilities (under new commitments). Relate your response to this question to the design priorities you articulate under question #3 above.

6. There was also general agreement among workshop participants that if adopted, an interim EPS should cover commitments (construction or contracts) five years or longer, which is also reflected in the Staff Straw Proposal. Do you agree? Why or why not? How does this design parameter achieve (or not achieve) the priorities you have identified under question #3 above?

7. Another major design issue discussed at workshops was what the Commission should look at (contract or facility operation) in determining whether the EPS applies. In particular, should the Commission (1) look at the operation of the facility underlying a contract[16], or (2) only to the amount/product contracted for by the LSE? The Staff Straw Proposal takes the approach that, for specified contracts, the Commission should look at the expected operation and emissions of the facility, rather than just the contracted amount. [17] Please comment on the advantages and disadvantages of these two alternative approaches, and your position on this issue.

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[16] Or in the case of joint ownership of a power plant, the entire facility being constructed.

[17] As indicated in Appendix A, under the Straw Proposal the Commission would impute an emissions profile for unspecified contracts.

8. There was general agreement during the workshop that an interim EPS should *not* apply to peaking facilities or resources expected to operate relatively few hours during the year. Accordingly, the Staff Straw Proposal uses a definition for "covered resources" as those with an annual average capacity factor of 60% or greater, intending to cover resources operating as year-round base load and high-use intermediate and shaping facilities. Do you believe that this definition of covered resources is appropriate? In responding, please address the following:

> a. What types of resources do you believe the EPS should cover and whether you believe the straw proposal capacity factor (60% or greater) metric to define a covered resource will capture those resources.
>
> b. Present an alternative metric(s) for defining "covered resources" that you recommend, if you do not support the Staff Straw Proposal definition.
>
> c. Whether (and if so, how) the EPS should incorporate a research and development exemption for advanced coal or other technologies.

9. Another design issue discussed at the workshop was how the EPS should apply to specified contracts with more than one underlying covered resource (new or existing): Should the Commission apply the EPS to the "blend" of the resources/units, or require that each covered resource meet the EPS individually?

Under the Staff Straw Proposal, each individual covered resource must meet the EPS, with the exception of a renewable contract firmed with a non-renewable resource. In that case, the blend of the two must meet the EPS, rather than the individual resources/units.

Do you agree with this approach? Why or why not? In your response, present your view of the relative advantages and disadvantages of the alternate approaches, and discuss your recommendation in the context of your answer on design priorities under Question #3.

10. In the context of the Staff Straw Proposal, how should the Commission treat partial contracts under the proposed EPS? An example discussed at the workshop was a "summer product" contract for power from a specified coal plant. For partial contracts, should the Commission look at how the facility is operating during the duration of the contract commitment, at the MWhs being purchased relative to the full year of facility operations, or consider other approaches? Would your proposed treatment of partial contracts result in an exemption under the 60% capacity factor rule, even if that underlying facility would be a "covered resource" under average annual operation? Why or why not?

11. The Staff Straw Proposal allows for an exemption from the standard for specified units of 25 MW or smaller, based on the size of the facility under construction or providing power under a contract. However, there would be no size exemption for unspecified contracts of any size. In commenting on this aspect of the Straw Proposal, please address the following:

a. The MW level of the "small unit" exemption under this proposal. Do you support this exemption as proposed? Would you propose a different size exemption level and/or one specifically tied to projects qualifying under the self-generation incentives program? No exemption? Why or why not?

b. Basing the exemption on MWs delivered to the grid. In determining eligibility for the size exemption, the Staff Straw Proposal would subtract out self-generated power that was not delivered to the grid.

   i. Please indicate whether you agree with this approach to determining the size exemption, why or why not?

   ii. If the Commission adopts this approach, what type of information (and source of data) would need to be presented for the Commission to determine the amount of expected self-generation to subtract from the unit size?

c. Basing the exemption on the size of the unit being constructed or underlying a unit-specified contract, rather than the size of the contract. Please discuss the relative advantages and disadvantages of these alternate approaches to a size exemption, and indicate which you would recommend, should the Commission determine that a size exemption would be appropriate. (You may refer to your answer to the related Question 7, as appropriate).

d. No size exemption for any unspecified contracts. Do you support this approach? Why or why not?

12. Under the Staff Straw Proposal, the Commission would develop two separate standards for covered resources: 1) a "moderate" EPS to apply to existing resources and repowering and 2) a "high" EPS to apply to new resources. Both would be based on the performance of a combined-cycle gas turbine (CCGT). Please address the following questions in your comments on this approach:

a. Do you agree in concept with a dual standard as outlined in the Staff Straw Proposal, why or why not?

b. If the Commission adopted this approach, what performance standard do you recommend for the "moderate" and "high" EPS? Express your answer in terms of heat rates as a proxy for GHG emission rates. Explain why you chose these levels, and the source of data/calculations you used to develop them.

c. If instead you recommend a single EPS based on the performance of a CCGT for all new commitments (whether to new resources, existing or repowered facilities), provide your recommended performance standard (expressed as a heat rate), explain why you chose this level, and the source of data/calculations you used to develop it.

d. In responding to b. and c. above, be specific as to how you developed your CCGT reference standard and the data sources/calculations used. For example, did you base it on the expected performance of a modern CCGT newly placed in service, or at the end of its useful life, or an average of emissions from existing CCGTs, or another approach?

e. If you have alternate or additional recommendations for the EPS standard and calculation, please submit them.

13. There was general agreement at the workshop that the Commission should allow credit for cogeneration thermal load when applying the EPS to covered resources. This is reflected in the Staff Straw Proposal. Do you agree with this approach, why or why not?

If you have developed a specific formula for the calculation of such a credit, please provide it in an attachment to your post-workshop comments, or in a separate joint submittal at the same time (if you are joining in with other parties on this issue). Indicate whether it is consistent with methods used to credit thermal loads in other emissions regulations for cogeneration facilities, either in California or elsewhere.

14. Do you have a position on how to calculate the net emission rates from renewables (e.g., for waste-to-energy, geothermal resources) for the purpose of applying the EPS? If so, please present your views either in your individual post-workshop comments or jointly with other interested parties at the same time.

15. There was discussion during the workshop on how to address unspecified contracts, i.e., what imputed emissions factor to use. The following alternatives were identified:

a. Western Energy Coordinating Council (WECC) system average;
b. Appropriate geographic average (e.g., Northwest purchases represent different resources than purchases from the Southwest);
c. California Energy Commission (CEC) "Net System Power" calculations;
d. Default to coal emission rates.

Please discuss your recommended approach, and why. Be as specific as possible as to the source of the data (or specific numbers) you would use for this purpose.

16. The Staff Straw Proposal does not include offsets or market price safety valves under the interim EPS, but does provide for a case-by-case reliability "safety valve" review by the Commission. (See Appendix A). Please comment on this aspect of the proposal, and provide your recommendations.

17. From a policy perspective, please discuss whether energy service providers, qualifying facilities (QFs) and other jurisdictional load-serving entities (LSEs), including

multi-jurisdictional utilities, should be subject to an interim EPS along with PG&E, SCE and SDG&E, should the Commission decide to adopt one. Limit your comments to policy considerations, rather than legal argument. [18]

If you have considered the issue of how the Commission would apply an interim EPS to multi-jurisdictional utilities, please present a protocol for allocating emissions among resources serving multiple states with your post-workshop comments.

18. If the Commission adopted an interim gateway EPS modeled after the Staff Straw Proposal, what documentation should it require "at the gate" with respect to 1) meeting the small size exemption, including amount of power delivered to the grid (for self-generation), 2) demonstrating whether the new commitment meets the "covered resource" definition or not, 3) claiming the cogeneration thermal load credit and 3) other requirements of the EPS?

Should there also be compliance requirements under this gateway approach (e.g., with respect to unspecified contracts), and if so, what should they be?

19. Staff Straw Proposal raises the issue of how to attribute emissions factors to renewable resources that have sold off their renewable energy credits (e.g., to municipal utilities) for the purpose of applying the EPS. There was some discussion of this "null power" issue at the workshop. Options discussed included imputing an emissions rate from the WECC region or from the region where the renewable power was located, or using the CEC's "net system power" calculation as a default emissions rate. If you have a recommendation on this issue, please provide it in your comments.

20. Please comment on any other aspects of the Staff Straw Proposal and alternative EPS designs for Commission consideration that are not covered in your answers to previous questions.

21. As reiterated in Judge Gottstein's September 30, 2006 notice to the service list, the utilities and other workshop participants agreed to prepare information/analysis on topics related to the threshold policy and implementation design considerations for an interim EPS. Some of this information will be available and distributed to the service list prior to the preparation of post-workshop comments.

As appropriate, please comment on how you have used this information in developing your post-workshop comments. What additional information/analysis do you believe would be useful to the Commission in considering the policy and implementation questions posed above?

[18] Legal briefs on jurisdiction and related issues are being filed separately.

**Attachment 1**

## Interim GHG Emissions Performance Standard
## California PUC Rulemaking 06-04-009

## CPUC Staff Straw Proposal for Discussion

### 1. Design Goals for the EPS

a. Prevent backsliding and commitments that will make future GHG reductions more difficult
b. Minimize costs to ratepayers and minimize the risk of long-term commitments that will raise the cost of future compliance costs
c. Reliability:
   i. short-term: don't force shutdown of essential facilities
   ii. long-term: consider risks of relying on high emitting resources
d. Administrative simplicity

### 2. Timeframe

a. Coordinate with procurement proceeding, but adopt now
b. Implement performance standard as interim measure for an unspecified period of time. CPUC will re-evaluate the program when a GHG cap and trade system or other relevant policy (CPUC, state, regional, or other) is functioning.

### 3. To Which LSEs does the EPS apply?

a. Apply to all jurisdictional LSEs (including ESPs and CCAs)
b. Create ESP process to address ESP procurement related to this program
c. Don't delay pending legislation regarding publicly-owned utilities
d. Develop a filing/approval process for multi-jurisdictional utilities, including a protocol for allocating emissions among resources serving multiple states

### 4. Program Screens

a. The EPS standard will be applied on a "gateway" basis, at the time a LSE's commitment (build or buy) is proposed.
b. The standard will be applied to the reasonably projected emission rate from the supply source over the term of the commitment

c. "Covered resources" are resources with a reasonably projected average annual capacity factor of 60% or greater.

5. **Which Power Sources are covered?**

**a.** Applied to utility owned **new generation, repowering or new/renewal contracts**
b. All new and renewal contracts and investments in "covered resources" of **five years or longer**
c. Applied to **baseload and intermediate or "shaping" facilities with annual average capacity factor of 60% or greater**
d. Size threshold:
--For **specified facilities (built or under contract): 25 MW or greater** delivered to the grid;
--For **unspecified resource/facilities under contract: all sizes**
e**.** Application to QFs addressed in legal briefs
f. Self-generation is covered (size threshold determined based on amount delivered to grid; cogeneration thermal load credit calculated, see below).
g. Renewables are covered, emissions factors can be demonstrated at the time of review (includes biomass, waste-to-energy, geothermal, etc.)
h. Reliability exemption considered on a case-by-case basis

6. **What is the Standard and How Determined?**

a. Emissions standards based upon CCGT performance
   i. Higher standard for new facilities : high-performing new CCGT
   ii. Moderate standard for existing facilities and repowering – keyed to performance of existing CCGT fleet
   iii. Allowance for cogen thermal load

b. Potential R&D exemption on a case-by-case basis (e.g., permit advanced coal facilities that have the capacity to capture and store carbon dioxide "safely and inexpensively" as described in the GHG Performance Standard Policy Statement?).

7. **How to apply the standard to units and contracts**

a. For single unit specific contracts: applied on facility basis
b. For multi-unit contracts: each covered unit must qualify

c. Baseload renewable product with firming fossil (that qualifies as a "covered resource") -- applied to baseload blend average. If firming unit is unspecific impute appropriate emissions factor.
d. Treatment of null renewable power? Not addressed at this juncture.
e. Unspecified resource contracts: apply appropriate emissions factor. Choices are:
    i. WECC system average
    ii. Appropriate geographic average (e.g., NW is different from SW)
    iii. CEC "Net System Power" calculations
    iv. Default to coal emission rates

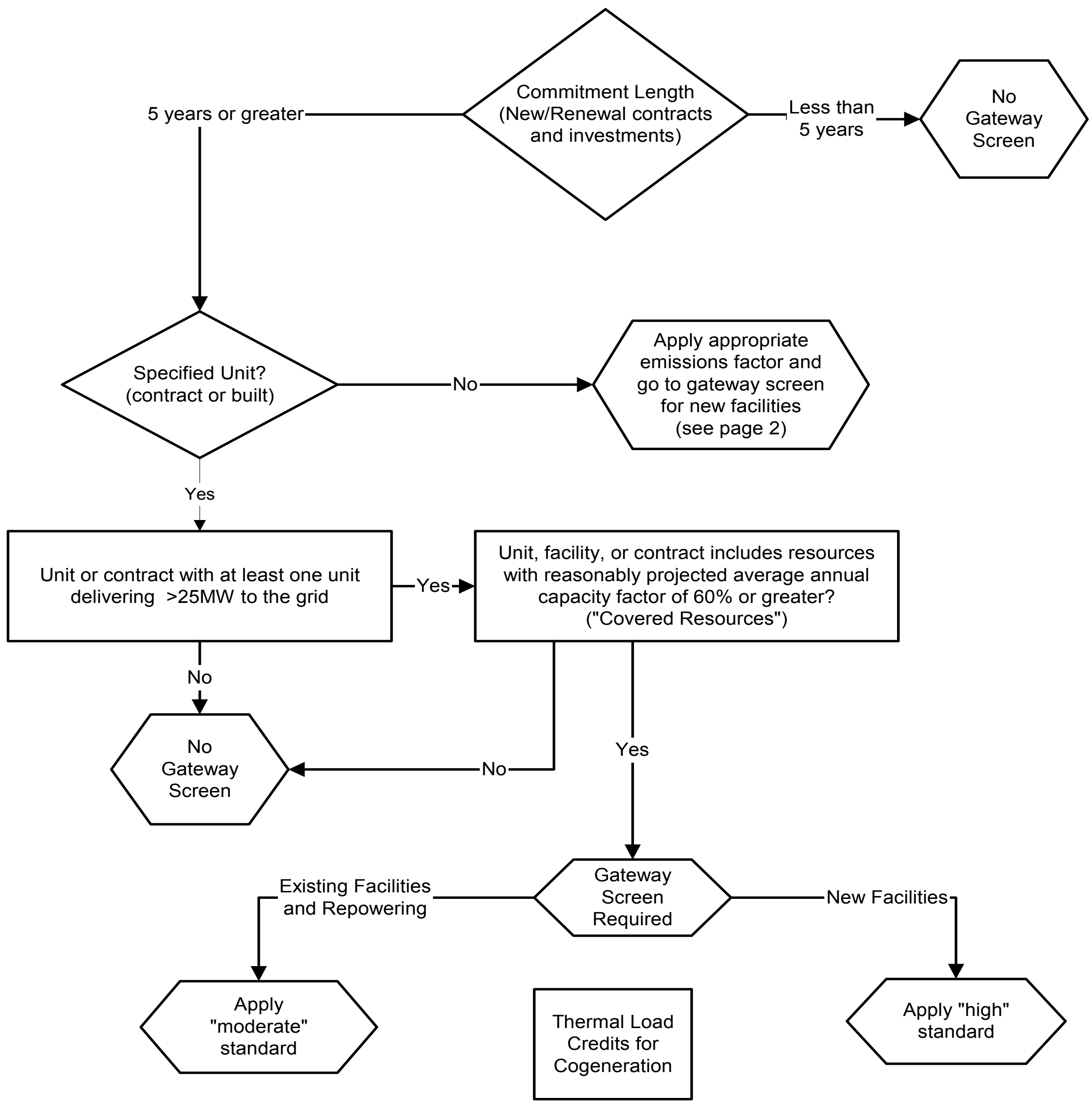
**8. Monitoring and Enforcement**

a. CPUC gateway review with documentation and approval required prior to finalizing contract or commitment to construct

**9. Offsets, Safety Valves, and other flexibility devices**

a. No offsets or market price safety valves
b. Case-by-case "safety valve" upon application and CPUC review for reliability only.

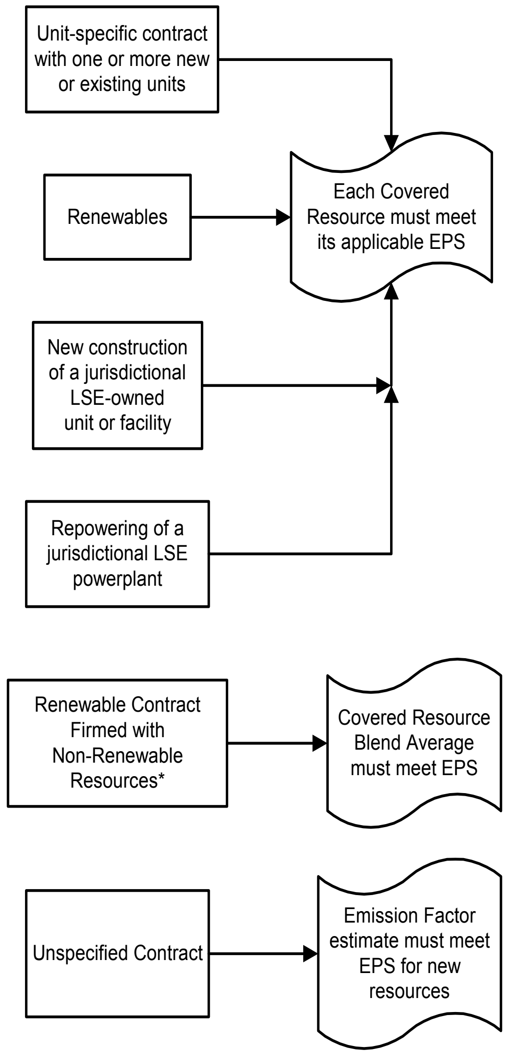
# EPS Screen –
# Which Commitments are Covered?




**Emissions standards based upon CCGT performance**
i. Higher standard for new facilities: high-performing new CCGT
ii. Moderate standard for existing facilities and repowering - keyed to performance of existing CCGT fleet

# Contract and Unit Specific Requirements to Meet EPS

**Note:**
Applicable EPS depends on whether the commitment involves a new versus existing covered resource. Repowering is measured against the EPS that applies to existing covered resources. Unspecified contracts use appropriate emissions factor and are subject to the EPS that applies to new covered resources.




**Emission Factor Options for Consideration Include:**
i. WECC system average
ii. Appropriate geographic average- (e.g., NW is different from SW)
iii. CEC "Net System Power" calculations
iv. Default to coal emission rates

* **Note:** If renewable contract is firmed with unspecifed power, then that firming resource will need to be assigned an appropriate emissions factor. The resulting "blend" average must meet the EPS.

### Issues not finalized in Staff Straw Proposal